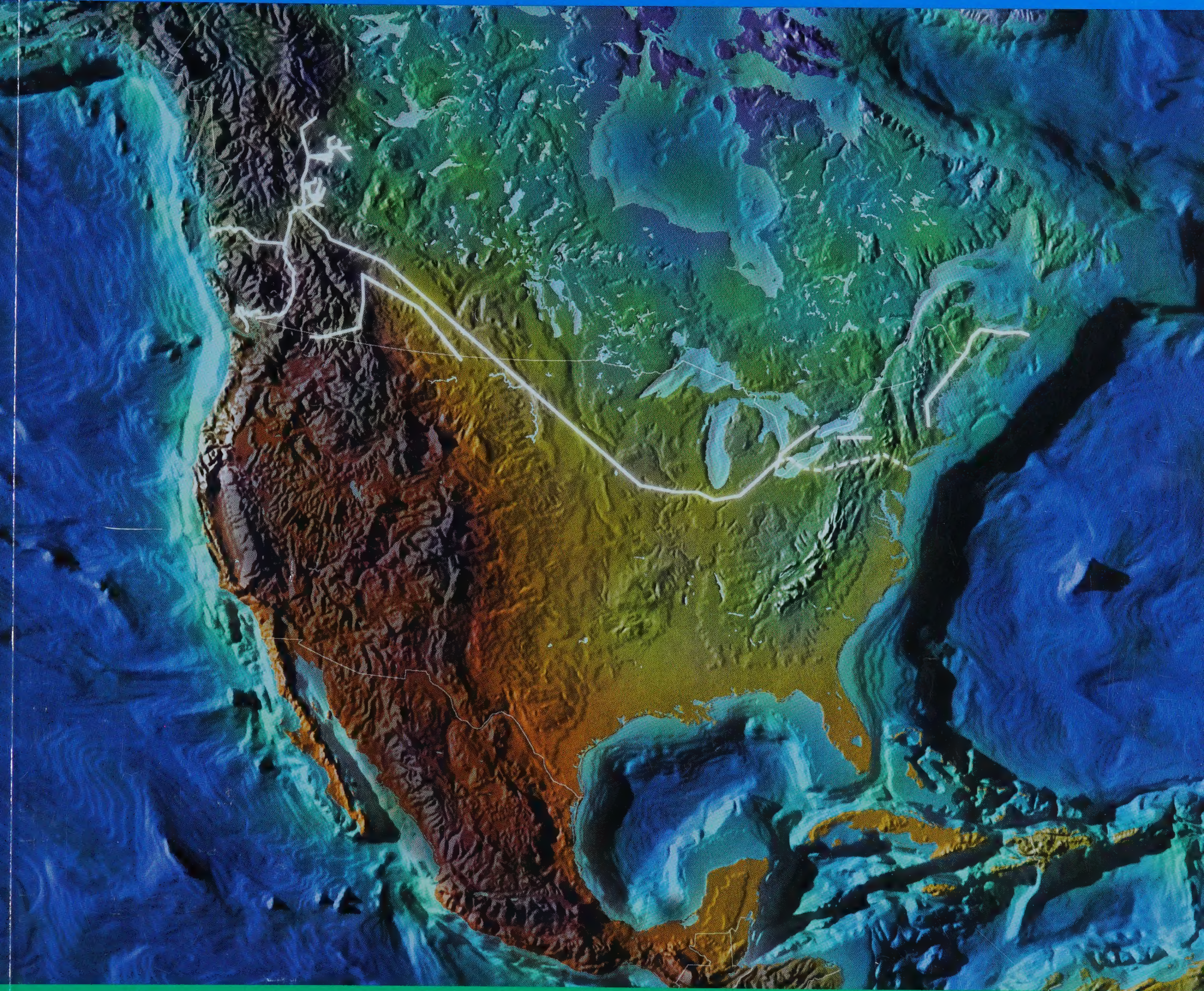
Westcoast Energy Inc.

ANNUAL REPORT 2000



Linking New Supply to Growing Markets

Westcoast Energy Inc. is a leader in the North American energy industry. Natural gas, a clean-burning, economical and plentiful energy source, is the foundation of Westcoast Energy's operations and the Company's fuel of choice to provide superior energy services value to its customers.

Headquartered in Vancouver, British Columbia, Westcoast Energy operates a $15-billion network of natural gas gathering, processing, transmission, storage and distribution assets, and related power generation, international, financial, information technology and energy services businesses.

Westcoast Energy At-A-Glance

Total assets	$15.1 billion
Operating revenues	$8,955 million
Net income applicable to common shares	$340 million
Employees	5,455
Natural gas pipelines	54,316 kilometres
Natural gas volumes	3,564 billion cubic feet
Natural gas distribution customers	1.2 million
Natural gas storage capacity	146 billion cubic feet
Natural gas marketed	1,809 billion cubic feet
Electric power marketed	10 million megawatt hours
Power generation plant capacity	422 megawatts
Stock symbols	Canada (TSE) – W United States (NYSE) – WE
Shares outstanding	121.4 million
Earnings per common share	$2.92
Dividends per common share	$1.28

Common Shares

Common Shares	2000	1999	1998
Shares outstanding at year-end	**121,443,366**	114,847,515	112,670,767
Toronto Stock Exchange price ranges – high	**$36.60**	$31.60	$36.35
Toronto Stock Exchange price ranges – low	**$20.10**	$22.40	$27.25
Number of common shareholders at year-end	**8,047**	8,556	8,645

Key Dates (tentative)

Quarters 2001	Release of Financial Results	Common Share Dividend Payment Dates
1st Quarter	April 25, 2001	June 30, 2001
2nd Quarter	July 26, 2001	September 30, 2001
3rd Quarter	October 24, 2001	December 31, 2001
4th Quarter	February 13, 2002	March 31, 2002

Transmission & Field Services

Westcoast Energy's natural gas gathering pipelines, processing facilities and transmission systems connect natural gas supplies and markets across North America – from Fort Liard, Northwest Territories to Goldboro, Nova Scotia.

	System Length	2000 Volumes
BC Pipeline and Field Services Divisions [100%]	5,480 km	682 Bcf
Empire State Pipeline [100%]~	252 km	117 Bcf
Foothills Pipe Lines [50%]	1,040 km	1,155 Bcf
Maritimes & Northeast Pipeline [37.5%]	1,369 km	290 Bcf
Vector Pipeline [30%]	553 km	*
Alliance Pipeline [23.6%]	3,686 km	*
Millennium West Pipeline Project [100%]	75 km	**
Millennium Pipeline Project [21%]	611 km	**

Gas Distribution

Westcoast Energy's natural gas distribution systems deliver energy to more than one million customers. The Company's underground storage facilities are the largest in Canada and, together with connected transmission systems, deliver natural gas to markets in eastern Canada and the central and eastern United States.

	System Length	2000 Volumes	Customers
Union Gas [100%]	34,772 km	1,263 Bcf	1,123,000
Centra Gas British Columbia [100%]	3,567 km	26 Bcf	69,000
Pacific Northern Gas [41%/100% voting shares]	3,597 km	31 Bcf	40,000

Power Generation

Westcoast Energy's power generation projects generate electrical and thermal energy from natural gas.

	Capacity	2000 Output
Ford Cogeneration Plant [100%]	35 MW	87,200 MWh
Fort Frances Cogeneration Plant [100%]	110 MW	745,200 MWh
Lake Superior Cogeneration Plant [50%]	110 MW	492,400 MWh
McMahon Cogeneration Plant [50%]	117 MW	854,100 MWh
Whitby Cogeneration Plant [50%]	50 MW	291,800 MWh
Island Cogeneration Project [100%]	250 MW	****
Bayside Power Project [75%]	285 MW	***
Frederickson Power Project [60%]	249 MW	****

International

Westcoast Energy's international businesses provide electric power, natural gas compression and liquids recovery, and nitrogen production and transmission services to markets in Indonesia, China and Mexico.

	Capacity	2000 Output/Volumes
P.T. Puncakjaya Power [43%]	388 MW	1,717,087 MWh
Shanghai Power Plant [32.5%]	50 MW	187,400 MWh†
Campeche Natural Gas Compression Services Project [45%]	250 MMcf/d natural gas compression and liquids recovery	***
Cantarell Nitrogen Facilities [20%]	1,200 MMcf/d nitrogen production 95 km nitrogen pipeline 500 MW	*

Services

Westcoast Energy's services businesses offer energy-related equipment, billing and customer information systems, financing, and natural gas and electricity marketing services across North America.

Engage Energy [100%]
Enlogix [100%]
Union Energy [100%]
Westcoast Capital [100%]
NGX Canada [49%]‡

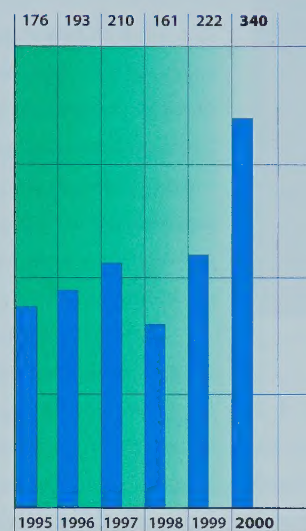
*	began operation Q4 2000
**	proposed
†	began operation Q2 2000
***	expected to begin operation Q2 2001
****	expected to begin operation mid-2002
~	purchase of additional 50% interest expected to close Q1 2001
‡	remaining 49% interest sold in Q1 2001

km	kilometres
Bcf	billion cubic feet
MMcf/d	million cubic feet per day
MW	megawatts
MWh	megawatt hours

Financial Summary

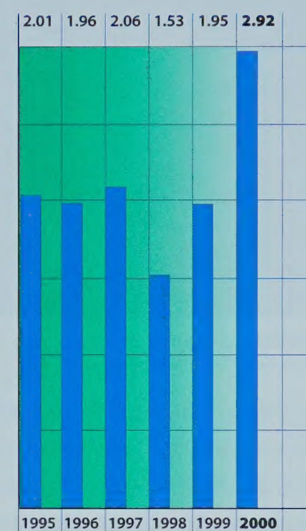
- Net income applicable to common shares was a record $340 million in 2000, $118 million higher than in 1999.
- On a weather-normalized basis, after eliminating the effect of corporate income tax rate reductions and the sale of Centra Gas Manitoba in 2000 and 1999, respectively, 2000 earnings per common share totalled $2.56, compared with $1.58 in 1999.
- Capital expenditures and investments in 2000, the final year of the Company's three-year, $4-billion capital expansion program, totalled approximately $1.3 billion, compared with $1.5 billion in 1999. Capital expenditures for 2001 are budgeted to total approximately $750 million.
- During 2000, Westcoast Energy completed a public offering of 4 million common shares with total proceeds of approximately $129 million. The additional common equity strengthened the Company's financial position and funded the acquisition of a further interest in the Empire State Pipeline.
- During 2000, the Company paid common share dividends totalling $1.28 per share. In February 2000, the Company announced that it was increasing its annual common share dividend from $1.28 to $1.36.
- During 2000, Westcoast Energy's common share price increased 56% from $23.15 to $36.20 (TSE). The Toronto Stock Exchange Pipelines Sub-Index, the Company's industry peer group, recorded a total return of 54%. The Toronto Stock Exchange 300 Index, a broad measure of Canadian equity market performance, recorded a total return of 7%. The increase in the Company's common share price, combined with an annual common share dividend of $1.28, resulted in a total common shareholder return in 2000 of approximately 62%.

For the years ended December 31 ($million)	2000	1999	1998
FINANCIAL			
Operating revenues	**8,955**	6,265	7,376
Net income	**388**	267	198
Net income applicable to common shares	**340**	222	161
Operating cash flow	**641**	499	448
Total assets	**15,127**	11,777	10,820
Per common share (dollars)			
– Earnings	**2.92**	1.95	1.53
– Dividends	**1.28**	1.28	1.26



Net Income Applicable to Common Shares

$million

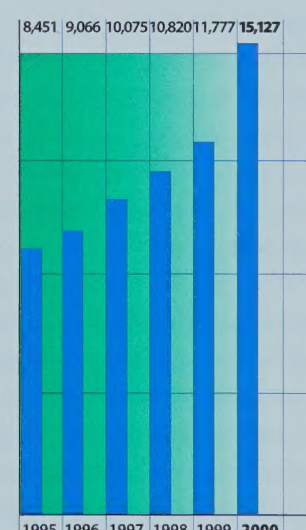


Earnings per Common Share (EPS)

dollars

Weather Normalized EPS

dollars



Total Assets

$million

KEY DATES (tentative)

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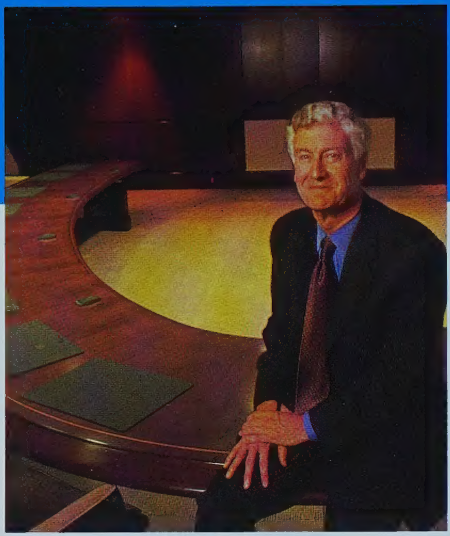
Chairman's Letter



Michael E. J. Phelps
Chairman and Chief Executive Officer

This past year marked the completion of a significant chapter in the history of Westcoast Energy. In 2000, we concluded the third and final year of a $4-billion capital expansion and investment program, the largest ever undertaken by the Company. The theme of this year's Annual Report, **Linking New Supply to Growing Markets**, signifies how this investment strategy has created a truly continental footprint, one that positions us for a bright future.

The year 2000 was one of significant success for Westcoast Energy. Our major investment projects have commenced operation or are in the final stages of completion. Our North American natural gas transmission footprint is now operational and our completed projects are generating revenue and contributing to net income. Our shareholders have begun to reap the benefits of this major capital expansion program and the strategic position it has given us in the North American natural gas market.

Our British Columbia pipeline system has been further extended into the Northwest Territories with the connection of new reserves at Fort Liard. Start-up of the Alliance and Vector pipelines has linked us to key natural gas markets in Eastern Canada and the American heartland. We completed construction of two major lateral pipelines for the Maritimes & Northeast Pipeline, extending service to Atlantic Canadian markets.

We now have more cross-border pipeline connections than any other natural gas pipeline owner. We provide the key links between Canadian natural gas supply and some of the most significant markets in North America, reflecting our recognition of the growing integration of the North American natural gas industry.

These projects have also enhanced the value of our other core businesses. With the completion of Alliance and Vector, and with our agreement to purchase the balance of the Empire State Pipeline, we have measurably increased the strategic value of the Dawn storage facility and the Dawn-Trafalgar pipeline system operated by our Union Gas subsidiary.

We successfully negotiated the dissolution of our Engage Energy joint venture and regained 100% ownership of Engage Energy Canada, a vital energy marketing and merchant trading company. Total ownership allows us to more fully focus its activities on Westcoast Energy strategies; we can now integrate our power generation, business development, pipeline capacity and trading capabilities into a coordinated whole, offering new products and services to growing markets.

In 2000, Union Energy operated on a break-even basis, our goal for this turnaround year. We believe that this energy equipment sales, service and finance business offers future growth opportunities.

We are also developing new businesses extending our expertise beyond the traditionally defined energy sector. We are now offering financing options through our Westcoast Capital subsidiary, and providing energy billing services, some of them Web-based, through our Enlogix subsidiary.

We continue to seek out new business models and new developments in information technology to ensure that we serve customers more quickly and efficiently, manage our costs and expand our revenue base.

Our international investments are progressing with the imminent completion of our major projects in Mexico and our ongoing operations in Indonesia and the People's Republic of China.

Our strategy has been centred on the belief that natural gas demand will grow. We expect that some commodity price moderation in the near term will accelerate this phenomenon. We anticipate continued strength in demand for natural gas from power markets. As a result, Canadian natural gas and the required transportation links should enjoy unparalleled opportunity. Westcoast Energy is the only natural gas transportation company linking offshore Nova Scotia, the Northwest Territories and the growing northeast British Columbia supply areas to these vibrant markets.

Our goal in expanding Westcoast Energy over the past three years has been to enhance the value of our shareholders' investment. We are linking new supply to growing markets with a focused goal – to enhance shareholder value.

2000 Results Show our Success

Our 2000 results reflect our focus on growth to build value:

- Net income applicable to common shares was a record $340 million in 2000, compared with $222 million in 1999.
- Earnings per common share were a record $2.92 in 2000, compared with $1.95 in 1999. On a weather-normalized basis, earnings per common share were $2.96 in 2000 compared with $2.10 in 1999.
- Total assets were $15.1 billion in 2000 compared with $11.8 billion in 1999.

This growth, diversification and expansion of income enhancing activities is being recognized by the equity markets and by our investors. Our share price increased from a

Our transmission and field services businesses **contributed $188 million to net income** in 2000, compared with $154 million in 1999.

1999 year-end closing price of $23.15 to a year-end close in December 2000 of $36.20. Westcoast Energy shareholders have benefited from a total return of 62% over 2000 and an 18% return per year over the past five years.

Expanding our Transmission and Field Services Footprint

Our transmission and field services businesses contributed $188 million to net income in 2000, compared with $154 million in 1999. This solid increase was mainly the result of new pipeline projects and increased utilization of our British Columbia gathering and processing facilities as producers responded to higher prices and increased demand for natural gas, particularly in the fall of 2000.

Our natural gas system in British Columbia, comprised of 5,480 kilometres of gathering and transmission lines and major processing facilities, moved some 682 billion cubic feet of natural gas during 2000 to markets in British Columbia, Alberta, and the U.S. Pacific Northwest.

In February 2000, we signed an agreement with the West Liard Valley Producers Group to process and transport natural gas from the southern Northwest Territories through our Fort Nelson, British Columbia facilities. With some 140 million cubic feet per day of processed natural gas now using our system, we expect volumes to grow with further exploration and development.

In Alberta, we own 50% of Foothills Pipe Lines, which transports some 1,155 billion cubic feet of natural gas each year, about 20% of Canada's natural gas exports, to markets in the U.S. Foothills operates Phase I – or the Prebuild – of the Alaska Natural Gas Transportation System (ANGTS) permitted to deliver Canadian natural gas to the U.S. in advance of the flow of northern supplies.

Foothills and its affiliates hold various permits and approvals from Canadian and U.S. legislative and regulatory authorities to proceed with the continuation of the ANGTS. We believe that the ANGTS offers a viable, economic, timely and efficient way to move natural gas from Alaska.

In addition, we are working with TransCanada PipeLines, our partner in Foothills, and others to examine the feasibility of moving natural gas from the Mackenzie Delta to markets in the south when sufficient reserves are proven to justify the investment.

On December 1, 2000, the $5.3-billion Alliance Pipeline and associated Aux Sable liquids facility, in which we own a 23.6% interest, were put into service. The Alliance Pipeline transports some 1.3 billion cubic feet of liquids-rich natural gas per day from northern Alberta and British Columbia to the Chicago area market hub. The Aux Sable facility recovers and markets associated liquids taken from the delivered natural gas.

The start-up on December 1, 2000 of the Vector Pipeline, in which we have a 30% interest, offers opportunities to move new natural gas supplies entering the market at Chicago to new and current customers through our Union Gas system.

In November 2000, we agreed to purchase, at a cost of US$75 million, the remaining 50% of the Empire State Pipeline that we did not already own. The 252-kilometre pipeline moves natural gas from Niagara Falls to upper New York State.

These new pipelines, integrated with our Union Gas storage assets and the Dawn-Trafalgar pipeline system, provide new links to serve our current customers and reach new markets in Canada and the U.S.

On the Atlantic Coast, full operation of the Maritimes & Northeast Pipeline (M&NP), in which we have a 37.5% interest, began in December 1999. M&NP transports 530,000 million British Thermal Units of natural gas per day from Goldboro, Nova Scotia, to markets in the Maritime provinces and New England states.

In 2000, M&NP completed construction of two important pipeline laterals: a 124-kilometre lateral to serve the Nova Scotia Power electricity generating station at Dartmouth, and a 102-kilometre lateral to serve the city of Saint John, New Brunswick, our Bayside Power Project and a pulp mill.

In August 2000, M&NP received permission from the National Energy Board to operate the Point Tupper Lateral at 50% of the applied for maximum operating pressure. M&NP is in discussions with the pipeline builder, Sable Offshore Energy Inc., regarding transfer of ownership of the line and placing it into service in early 2001.

In last year's letter to shareholders, I predicted that 2000 would see the operation of our North American footprint. Today, this web of cross-border pipelines links gathering systems from as far north as the Northwest Territories with markets from California to Chicago to Boston and New York. We are also favourably positioned to be part of the next significant expansion linking the supply basins in the Alaska North Slope and the Mackenzie Delta to southern markets.

Levering our Natural Gas Distribution Assets

Our natural gas distribution businesses in Ontario and British Columbia continue to be solid core assets. This year our Union Gas subsidiary had a very successful year,

The Year:

A Continental Presence

With completion of the Alliance and Vector pipelines, new natural gas supply is reaching growing markets in Canada and the United States and increasing the strategic value of the Company's Dawn hub.

In December 2000, the 3,686-kilometre Alliance Pipeline began moving 1.3 billion cubic feet of natural gas per day to the Chicago, Illinois area market centre, linking Western Canadian natural gas with growing markets in the U.S. Midwest.

The 553-kilometre Vector Pipeline also began service in December 2000, connecting 700 million cubic feet of natural gas per day at the market centre at Chicago, Illinois to growing markets in Eastern Canada and the U.S. Northeast.

In 2000, Westcoast Energy and its partners completed construction of the Cantarell Nitrogen Facilities in Mexico, the **world's largest nitrogen extraction and injection plant.**

contributing $97 million to net income compared with $79 million in 1999.

Union Gas' strong contribution in 2000 was a result of colder weather, effective cost management and an increase in revenue from both traditional and new sources. While weather in 2000 was colder than in 1999, it was the third consecutive year of warmer than normal weather.

During 2000, we added additional storage capacity in Ontario and achieved steady growth in transaction volume at our Dawn hub. Our Dawn hub continues to add considerable value as a strategic asset in our Union Gas portfolio.

The major initiative for Union Gas in 2000 was a proposal to alter the way in which Union Gas manages its business. Performance-based regulation (PBR) will offer Union Gas an opportunity to provide services to customers at competitive market rates and retain some of the benefits of improvements in business efficiencies. PBR will also minimize regulation, reduce costs and improve our capability to respond to customer needs in an increasingly competitive energy market. Hearings on the proposal were held before the Ontario Energy Board throughout the year; a decision is expected in the first quarter of 2001.

Union Gas continued to increase both its customer base and the volumes of natural gas distributed in its market area. In 2000, we were able to add 24,400 new customers and increase the volume handled by our system by 3.4% over 1999, setting a new record.

Centra Gas British Columbia operates an underwater natural gas transmission pipeline to, and distribution facilities on, Vancouver Island. Centra Gas British Columbia continues to grow and expand on Vancouver Island. In 2000, it increased its customer base by 4.5%. Contribution to net income in 2000 was $14 million compared with $12 million in 1999.

Pacific Northern Gas (PNG), 41% owned by Westcoast Energy operates a pipeline in west-central British Columbia and distribution facilities in several northeast British Columbia communities.

Reaching New International Markets

Our international investments contributed $29 million to net income in 2000, compared with $15 million in1999.

In 2000, Westcoast Energy and its partners completed construction of the Cantarell Nitrogen Facilities in Mexico, the world's largest nitrogen extraction and injection plant. The $1.5-billion facilities, in which Westcoast Energy has a 20% interest, consist of four air separation units (ASUs), each larger than any previously operated. All four ASUs, with an aggregate design capacity of 1,200 million cubic feet per day of nitrogen, have been performance tested and are now in operation. The nitrogen is being injected into the Cantarell oil field assisting Petróleos Mexicanos (PEMEX) to maintain production from the Cantarell oil field.

The Campeche Natural Gas Compression Services Project neared completion at year-end. This project, located offshore in the Gulf of Campeche, will take 250 million cubic feet of sour natural gas per day from oil fields in the area, separate water and liquids from it, compress it, and pipe it to shore for sale or use by PEMEX. Westcoast Energy owns 45% of this $410-million project, one of the first in which non-Mexican companies have been allowed direct ownership of projects in the energy sector.

These two projects have been major success stories for our Company and have provided measurable benefits to Mexico. Nitrogen injection has increased oil production, ensuring the additional recovery of millions of barrels of crude oil from a maturing field. This represents a new source of revenue for PEMEX. Similarly, natural gas gathered at our Campeche facility will be shipped to shore instead of being flared. In addition to the environmental benefits, this facility will deliver a new fuel source for the region.

We have transferred our expertise and our capital to a new host country, assisted Canadian suppliers to find new markets and developed important business relationships that will offer future business opportunities.

In Shanghai we are a 32.5% owner of the Shanghai Power Plant, which began commercial operation in June 2000. This 50-megawattt plant uses blast furnace gas, a waste fuel, to supply power to an adjacent steel plant.

We continue to manage our 43% interest in the P.T. Puncakjaya Power facilities in Irian Jaya, Indonesia. The project generates 388 megawatts of electric power for an adjacent mine. The project contributed some $14 million to net income in 2000, compared with $12 million in 1999.

In 2000, we recorded an after-tax gain of $8 million on the sale of our 74% interest in the EastCoast Power Project in Australia.

Powering New Sources of Energy

We believe that power generation opportunities will provide a real source of growth for Westcoast Energy in the future. We continue to actively seek out power generation development opportunities in regions near our existing assets or where we can bring some unique competitive advantage to the project.

In September 2000, Westcoast Energy

entered into a letter of intent to sell its interests in several operating power generation assets and the 100%-owned Island Cogeneration Project currently under construction. Significant changes in the power and natural gas markets since the signing of this letter of intent have complicated the transaction. The outcome of the negotiations is uncertain; however, market conditions have resulted in continued good performance of these assets.

Progress has been made on construction of the 75%-owned Bayside Power Project near Saint John, New Brunswick. This 285-megawatt combined cycle natural gas fired cogeneration plant is now nearing completion and is expected to begin operation in the second quarter of 2001.

In addition, we continue to develop the 249-megawatt Frederickson Power Project near Tacoma, Washington in which we have a 60% interest. Acquisition of the partially built plant was completed in August; construction activities are moving forward with an expected in-service date in mid-2002.

Finally, in February 2000, we sold our 50% interest in the Liberty Electric Power Project, a planned 500-megawatt plant in Pennsylvania, for an after-tax gain of $3 million.

Reaching New Markets in Energy Services

Our growing energy services group includes Engage Energy, Union Energy, Enlogix and Westcoast Capital. These new ventures provide the opportunity to both expand our business base and to enhance and extend the value of our core assets. We are defining areas along the energy value chain where we can bring a unique and powerful set of skills and create competitive advantage in the marketplace. It is here, where our knowledge of the energy business is a powerful asset, that we are able to generate new sources of revenue.

Engage Energy, a natural gas and electricity marketing and merchant trading company, provides us with a strategic window into the increasingly volatile and dynamic deregulated energy market. In October 2000, we reconstituted Engage Energy from a strategic joint venture that had allowed us to gain experience and build a North American expertise. We refocused and launched it with two objectives; optimizing the value of Westcoast Energy's portfolio of assets, and building its own unique business portfolio. Engage Energy will operate from offices in Canada, the U.S. Pacific Northwest and the central U.S. at Southfield, Michigan.

Engage Energy contributed $26 million to net income in 2000, compared with $5 million in 1999.

Union Energy, created in 1997, serves 1.1 million customers from 45 branches, providing heating, ventilating and air conditioning (HVAC) sales and services, and rental and financing plans. In 2000, Union Energy operated at a break-even level after suffering start-up losses in 1999 of $38 million. The turnaround in business operations, as planned, offers opportunities for future growth.

In 2000, Enlogix grew to become one of North America's largest providers of billing and

Corporate Responsibility

IN OCTOBER 2000, WESTCOAST ENERGY WAS ADDED TO THE DOW JONES SUSTAINABILITY INDEX, THE WORLD'S MOST PROMINENT GLOBAL SUSTAINABILITY INDEX TRACKING THE PERFORMANCE OF THE LEADING SUSTAINABILITY-DRIVEN COMPANIES WORLDWIDE. WESTCOAST ENERGY IS ONE OF 16 CANADIAN COMPANIES LISTED ON THE INDEX, AND THE SOLE CANADIAN COMPANY TO APPEAR IN THE GAS UTILITIES INDUSTRY GROUP.

Westcoast Energy has always valued its reputation among its stakeholders. In 1994, we began exploring how we might measure our success with economic, social and environmental criteria, and how we might use the results to enhance our stakeholder relationships and improve our reputation.

Our stakeholders have also expanded their definition of corporate success to include the sum total of economic, environmental and social performance – in other words, the considerations of sustainable development.

Making progress towards sustainable development benefits each of our stakeholders and, in turn, returns to us the benefits of employee and community support, competitive advantage and access to financial capital.

As a provider of key links between new natural gas supplies and growing markets, we understand the importance of addressing issues of climate change and the environmental impact of our continued growth.

We believe that natural gas, the least carbon intensive fossil fuel, offers part of the solution to climate change. We recognize, however, that providing natural gas is not without impacts, and remain committed to educating end-use consumers about energy conservation, and offering solutions for industry that turn waste products – such as blast furnace or flared natural gas – into usable energy.

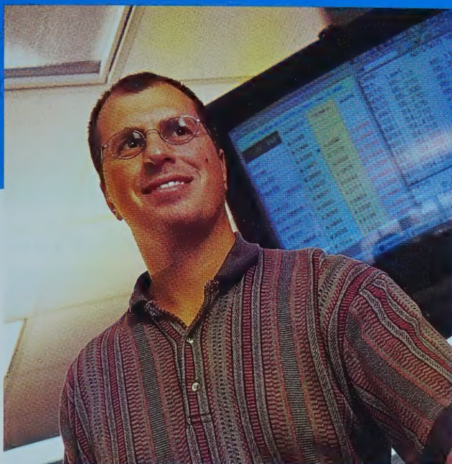
To help fulfil our social responsibilities, we continue to create partnerships with community organizations in order to support the areas where we live and work.

In 2000 we supported numerous not-for-profit groups, contributing a total of $1.5 million to charitable organizations, including:

* the Rotary Challenger Park in Calgary, Alberta, North America's first multi-sport facility designed for challenged and able-bodied athletes. This facility will serve as a prototype for the social integration of 100,000 individuals in the Calgary area;
* the Arts Umbrella Preschool Art Start Program in Vancouver, British Columbia, which supports learning through experiences in visual and performing arts. This program, together with the Westcoast Energy Children's Centre established in North Vancouver, British Columbia to assist children and their families, reflects the Company's focus on supporting adult success through early childhood development; and
* the Ed Shreyer Work Project in Windsor, Ontario, dedicated to building houses in partnership with families in need. Together with Habitat for Humanity Canada, Union Gas donated employee time, corporate funding and energy equipment to help create ten new homes.

As we continue to integrate sustainable development into our operations we will communicate our progress to stakeholders, share best practices, and ensure that we align our efforts with the expectations of the public, governments and the marketplace.

In 2000, we made **significant progress** towards reaching **our goals for growth and profitability** in our energy services businesses.



customer information services to the energy and utilities sectors. It now provides 13 clients with billing services for their 3 million customers. Clients include The City of Calgary, Portland General Electric, Union Gas and others. Enlogix systems now support clients in the unregulated natural gas, electric, water and energy services sectors across North America. We will aggressively continue our efforts to secure positive income contribution from this business.

Westcoast Capital offers customized financial services through a growing portfolio of financial products. In September 2000, Westcoast Capital completed a $363-million securitization of rental water heaters and other financial contracts, its largest transaction to date. In 2000, Westcoast Capital contributed $21 million to net income, compared with $8 million in 1999.

Over the past six years we built Natural Gas Exchange (NGX), an electronic trading floor offering natural gas pricing and trading at the Alberta Empress hub, into a major business entity. In February 2000, Westcoast Energy welcomed OM Gruppen of Sweden as a 51% partner in NGX, resulting in an after-tax gain of some $4 million. In January 2001, we sold the remaining 49% of NGX to OM Gruppen for an after-tax contribution to net income of $6 million.

New business ventures inherently require risk taking and innovation in their attempts to develop new products and services, find new customers and carve out new markets. However, each of these businesses must become profitable. In 2000, we made significant progress towards reaching our goals for growth and profitability in our energy services businesses.

Prudent Financial Management

We recognize the importance of modest and steady increases to our dividend. After ten quarters of steady dividends of 32 cents, the Board of Directors announced an increase of the quarterly dividend to 34 cents for the first quarter of 2001.

We also recognize the importance of generating funds internally to support high-quality investment opportunities such as M&NP expansion, further development of independent power projects, increased storage and transmission capacity at Union Gas, and British Columbia facilities expansion.

In November 2000, we issued 4 million new common shares at $32.25 per share to a consortium of underwriters to help fund our acquisition of the remaining 50% interest in the Empire State Pipeline. In addition, we issued 2 million common shares to existing shareholders under our Dividend Reinvestment and Share Purchase Plan for proceeds of $50 million.

In 1999 we launched an enterprise-wide initiative aimed at reducing our expenditures on materials and services. We consolidated Company-wide spending, streamlined and simplified our specifications and negotiated better deals with suppliers. We intend to continue this work and capture further efficiencies in 2001 and beyond.

Late in 2000, the Board of Directors concluded a review of our capital investment strategy and set a 2001 capital expenditure budget of $750 million, returning our planned capital expenditures to a level more consistent with our ability to generate funds internally.

The Year Ahead

While the last few months of supply and pricing fluctuations have raised concerns, the importance of natural gas has been clearly defined by growing market demand and strong pricing for this premium fuel. The commanding position and pricing for natural gas have shown that it is the fuel of choice for meeting the future energy needs of North America.

This is not likely to be a temporary phenomenon. With the expectation that natural gas prices will fall from recent winter peaks, we believe that the demand for natural gas will continue to increase and that North American demand could reach 30 trillion cubic feet (Tcf) per year in the next decade.

Supplying this growing demand for natural gas will require increased natural gas production, and increased infrastructure to process and transport it to markets. Much of the incremental supply will come from new areas, resulting in new or expanded pipelines.

The recent experience in California shows how tightly constrained a market can become if demand grows and new supply sources are not allowed to develop because of regulatory constraints or the disruption of natural market mechanisms.

We believe that all stakeholders will place more focus on ensuring the supply of energy, in particular natural gas, is available to meet current and future demand, when and where it is needed.

The current political climate in Canada, the United States and Mexico augurs well for continued cooperation in developing the supply response necessary to meet the 30-Tcf demand that we see in the future. The North American natural gas industry is increasingly integrated across international boundaries. Westcoast Energy is particularly well positioned to participate in the market-oriented response of

Canada, the United States and Mexico to the new energy dynamic.

We are looking forward to working with the new government in Mexico to expand on the partnerships we have already developed with both government and the Mexican energy industry. Mexico has become a major player in the North American energy picture and, as a full North American Free Trade Agreement partner, it will be integrated more fully into the North American energy market in the future.

The various sources of energy supply: oil, coal, nuclear, hydro-electricity and natural gas, are increasingly competitive and interchangeable. The North American market is becoming more complex. Winning as a North American energy firm requires the right mix of infrastructure, assets, services and intellectual capital.

Our capital investment program of the past three years could not have been better timed to meet the growing demand for natural gas. We are linking new supply to growing markets and we are doing it now, when our assets and services are most in demand.

Our focus in the future will be to apply our intellectual resources to maximize the productive value of these assets. We have the assets, our goal is to drive more synergy and more shareholder value from them.

We already have an enticing array of investment opportunities to choose from as North America seeks to respond to the demand for natural gas. Our challenge will be to choose wisely in the investment of our capital resources.

We expect to see a significant increase in exploration and development spending in all North American natural gas basins. We believe that the combination of growth in demand and attractive commodity prices will result in unprecedented levels of drilling, particularly in the northern parts of Alberta and British Columbia, in the southern Northwest Territories and on the Scotian Shelf.

The Alliance and Vector pipelines and the continued utilization of our British Columbia mainline system will ensure that Western Canadian natural gas is expeditiously and efficiently transported to markets to meet this growing North American demand. We will strive to ensure that these pipeline systems are fully utilized as supply develops to meet growing demand.

We expect to see heightened interest on the part of producers in finding the quickest and most efficient ways to move natural gas from the Alaska North Slope and the Mackenzie Delta. We plan to play a pivotal role in the development of both of these major new pipeline projects. There is room in a 30-Tcf world for both projects.

Recent new natural gas discoveries in the Scotian Shelf have provided concrete evidence that new natural gas resources will be available for expansion. We expect to see proposals for significant expansion of the M&NP system within a short period of time.

Our Union Gas storage and transmission assets will grow in strategic value. In our distribution business, we look forward to putting performance-based regulation into place at Union Gas and making it work for our customers and our shareholders.

We will continue to seek new power generation opportunities where we bring a competitive advantage to the project.

We will continue to prudently manage our international investments.

We will continue to drive our energy services businesses towards greater levels of profitability. Union Energy, Enlogix and Westcoast Capital represent real potential for growth and expansion beyond our core asset base.

Engage Energy represents a real and exciting opportunity for us. It offers the opportunity to create value by using the synergy of all our assets to optimize income generation. With Engage Energy now dedicated to serving Westcoast Energy strategies, we will see improvements in the way we manage all of our businesses for increased shareholder value.

We continue to aggressively search out every possible value enhancement tool available to keep our costs competitive. We are particularly mindful of the latest e-business and information technology enhancements and their potential applications to our business.

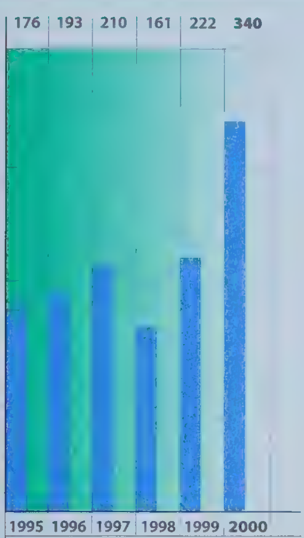
We continually rededicate ourselves to managing all our businesses in a safe and responsible way. We believe in sustainable development and strive to manage our businesses with regard for all our stakeholders. As always, we are mindful of the stakeholder support that is necessary to operate our businesses across Canada and throughout North America.

As we look forward into 2001, we invite shareholders to pay particular attention to the results of natural gas exploration and development, particularly in Western Canada. It is this new production that will serve to moderate commodity prices. This should boost demand, both for natural gas and for our transportation links.

For these reasons, we anticipate that our businesses will fare well in the coming years. A vigorous supply response should increase the near-term value of our transportation commitments on the Alliance and Vector pipelines, boost profitability at the Aux Sable facility and set the stage for more pipeline expansion.

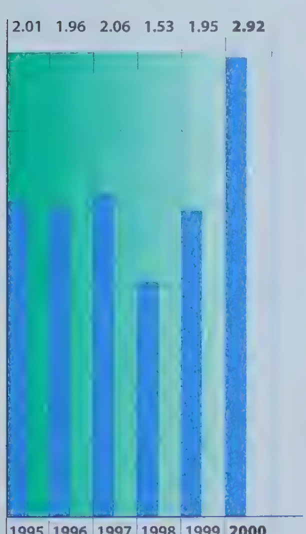
Finally, we believe that our success continues to rest on the contributions of our employees. The successful company of the future will be the one that is able to find, grow, challenge, reward, and retain the best employees possible. I believe we are such a company. We could not have become a $15-billion company without capable, talented and committed employees. On behalf of the Board of Directors, I thank each and every one of them for another successful year.

Michael E.J. Phelps
Chairman and Chief Executive Officer
March 1, 2001



Net Income Applicable to Common Shares

$million



Earnings per Common Share (EPS)

dollars

This discussion and analysis of the Company should be read in conjunction with the consolidated financial statements and accompanying notes. The results reported herein have been prepared in accordance with accounting principles generally accepted in Canada and are presented in Canadian dollars. The effects on net income arising from the variances between accounting principles generally accepted in Canada and the United States are described in Note 22 to the consolidated financial statements.

The consolidated financial statements include the accounts of the Company, its subsidiaries and its proportionate share of joint venture investments.

The Company realized higher earnings in 2000 and 1999 compared with 1998 as a result of colder weather experienced in 2000 and 1999 compared with the unusually warm temperatures in most of the Company's gas distribution franchise areas in 1998. While colder than 1998, weather was again warmer than normal in 2000 and 1999, which adversely impacted the Company's results. Weather normalized earnings per common share were $2.96, $2.10 and $1.90 for 2000, 1999 and 1998, respectively.

Fiscal 2000 results were also favourably impacted by the contribution of $46 million or $0.40 per common share arising from reductions in corporate income tax rates. As a result of federal and Ontario corporate income tax rate reductions announced in the first and fourth quarters of 2000 and to become effective in the period to 2004, the deferred income tax assets and liabilities have been adjusted to reflect the current and substantively enacted income tax rates. Normalizing for weather, the $0.40 per common share impact of the 2000 corporate income tax rate reductions and the $0.52 per common share gain on the 1999 sale of Centra Gas Manitoba Inc. (Centra Gas Manitoba), normalized earnings per common share were $2.56, $1.58 and $1.90 for 2000, 1999 and 1998, respectively.

CONSOLIDATED OPERATIONS

Years ended December 31 ($million)	2000	1999	1998
Net income applicable to common shares	340	222	161
Weather	5	17	39
Weather normalized earnings	345	239	200
Reduction in corporate income tax rates	(46)	—	—
Sale of Centra Gas Manitoba	—	(59)	—
Weather and significant items normalized earnings	299	180	200
($/share)			
Earnings per common share	$2.92	$1.95	$1.53
Weather	0.04	0.15	0.37
Weather normalized earnings per common share	2.96	2.10	1.90
Reduction in corporate income tax rates	(0.40)	—	—
Sale of Centra Gas Manitoba	—	(0.52)	—
Weather and significant items normalized earnings per common share	$2.56	$1.58	$1.90

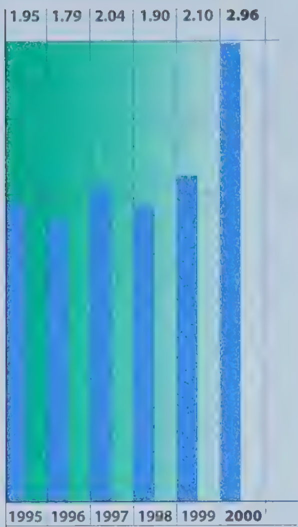
Both fiscal 2000 and 1999 enjoyed higher contributions from new pipeline projects and strong contributions from the British Columbia Pipeline and Field Services divisions, which benefited from increased throughputs and higher natural gas prices. The 2000 results showed continuing improved results from Engage Energy,[1] reflecting a strong performance by the gas and electric power trading operations, and from Union Energy Inc. (Union Energy), reflecting higher revenues and improved margins. Fiscal 2000 results also reflect customer growth and increased storage and transportation revenues at Union Gas Limited (Union Gas) and higher contributions from international projects.

The 1999 results, when compared with 1998, also reflect a marked improvement in the results of Engage Energy due to profitable structured natural gas and electric power transactions, improved risk management and a continued emphasis on cost containment. Earnings in 1999, however, were negatively impacted by lower allowed rates of return on common equity for the Company's regulated gas distribution businesses and Foothills Pipe Lines Ltd. (Foothills).

Divestitures in 2000 include the sale of the Company's 74% interest in the EastCoast Power Project in Australia, the 51% interest in NGX Canada Inc. (NGX) and the 50% interest in the Liberty Electric Power Project, which provided a total after-tax gain of $15 million or $0.13 per common share.

Earnings in 1999 were, on a net basis, increased by $0.18 per common share by certain unusual items. The major contribution was the gain on the sale of Centra Gas Manitoba ($59 million after tax or $0.52 per common share). The gain on the sale was partially offset by certain charges within the Company's retail energy services business, restructuring costs primarily resulting from business transformation initiatives at Union Gas, and the write-off of costs related to development projects, totalling $0.34 per common share. In total, and on a net basis, weather and the unusual items noted above increased earnings by $0.03 per common share in 1999.

(1) For the years ended December 31, 1999 and 1998 and for the nine months ended September 30, 2000, Engage Energy represents the Company's 50% interest in Engage Energy Canada, L.P. and Engage Energy U.S., L.P. With the termination of the joint venture agreement with The Coastal Corporation on October 2, 2000, Engage Energy represents the Company's 100% interest in Engage Energy Canada, L.P. and Engage Energy America LLC.



Weather Normalized EPS

dollars

Fiscal 1998 results include charges which reduced earnings by $0.11 per common share. These reflect Centra Gas Manitoba's disallowance of natural gas costs by the Manitoba Public Utilities Board (MPUB) net of recoveries, Engage Energy's loss arising from customer defaults, and the write-off of the Company's investment in a small unregulated natural gas processing plant. These were partially offset by the gain on the sale of Centra Gas Alberta Inc. (Centra Gas Alberta) and the gain on the sale of the Company's 50% interest in the Australian Eastern Gas Pipeline Project.

The increase in operating revenues and cost of sales in 2000 over 1999 primarily reflects the impact of increasing natural gas and electricity prices and the acquisition of the additional 50% interest in Engage Energy Canada L.P., increasing the Company's interest to 100%. In addition, transportation revenues from the Maritimes & Northeast Pipeline, commencing from the pipeline's December 1999 in-service date, and revenues from the Cantarell Nitrogen Facilities, commencing from their partial in-service date of June 2000, have also contributed to the increase, which is partially offset by the loss of revenues associated with the sale of Centra Gas Manitoba in July 1999.

Operating revenues and cost of sales decreased in 1999 compared with 1998 primarily due to lower trading activity by Engage Energy, offset partially by colder weather in 1999 compared with 1998 and the contribution generated in 1999 from 13 new heating, ventilation and air conditioning (HVAC) operations acquired by the Company's retail energy services business. Cost of sales in 1998 include unusual charges by Centra Gas Manitoba for certain natural gas costs related to price management activities which were disallowed by the MPUB, and also include Engage Energy losses arising from customer defaults.

Effective January 1, 2000, the Company adopted the new recommendations of The Canadian Institute of Chartered Accountants (CICA) with respect to accounting for income taxes. Under the new recommendations, the liability method of tax allocation is used in accounting for income taxes for non-regulated businesses. Under this method, deferred income tax assets and liabilities are determined based on substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Rate-regulated businesses of the Company continue to use the income taxes currently payable method as directed by the regulators and as provided under the new recommendations. The effective consolidated income tax rate for 2000 was 12.7%, compared with 14.2% in 1999 and 19.0% in 1998. The lower effective tax rate is mainly attributable to the impact of the federal and provincial income tax rate reductions recorded in 2000. Details of the consolidated income tax provisions are provided in Note 4 to the consolidated financial statements.

CONSOLIDATED QUARTERLY RESULTS

($million, except for share data)

	For the three months ended				
2000	**Mar-31**	**Jun-30**	**Sep-30**	**Dec-31**	**Total**
Operating revenues	1,754	1,761	2,130	3,310	8,955
Net income	130	82	36	140	388
Earnings per common					
share – basic	$1.03	$0.60	$0.20	$1.09	$2.92
– diluted	$1.01	$0.51	$0.20	$0.98	$2.79

($million, except for share data)

	For the three months ended				
1999	**Mar-31**	**Jun-30**	**Sep-30**	**Dec-31**	**Total**
Operating revenues	1,782	1,478	1,330	1,675	6,265
Net income	133	17	62	55	267
Earnings per common					
share – basic	$1.08	$0.05	$0.44	$0.38	$1.95
– diluted	$1.07	$0.05	$0.39	$0.27	$1.78

The fourth quarter results in 2000 were favourably impacted by colder than normal weather, compared with the warmer than normal weather experienced in the fourth quarter of 1999. Weather increased earnings by $0.05 per common share for the three months ended December 31, 2000 and reduced earnings by $0.05 per common share for the three months ended December 31, 1999.

Earnings in the fourth quarter of 2000 reflect the solid performance from the British Columbia Pipeline and Field Services divisions and Engage Energy, and the turnaround of Union Energy, for which 1999 fourth quarter results reflected certain items related to the start-up of the business. The Federal Budget in October also provided further corporate income tax rate reductions, which provided a contribution of $30 million ($0.26 per common share) in the fourth quarter of 2000. After adjusting for weather and the corporate income tax rate reductions, normalized earnings per common share for the three months ended December 31, 2000 and 1999 were $0.78 and $0.43, respectively.

RESULTS BY BUSINESS SEGMENT

The operations of the Company are grouped according to the following business segments:

- Transmission & Field Services - natural gas gathering, processing and transmission;
- Gas Distribution - natural gas distribution and storage and transmission;
- Power Generation - electrical and thermal energy generated from natural gas;
- International - international operations;
- Services - energy marketing, retail energy services, information technology and financial services;
- Other - other activities, including corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

The contribution to net earnings by these business segments, after allocation of acquisition costs, was:

Years ended December 31 ($million)	2000	1999	1998
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES			
Transmission & Field Services	188	154	128
Gas Distribution	112	154	122
Power Generation	16	11	6
International	29	15	16
Services	45	(32)	(46)
Other	(50)	(80)	(65)
	340	222	161

Additional segmented information is provided in Note 21 to the consolidated financial statements.

TRANSMISSION & FIELD SERVICES

The contribution to net earnings for Transmission & Field Services was:

Years ended December 31 ($million)	2000	1999	1998
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES			
British Columbia Pipeline and Field Services Divisions	109	93	104
Non-NEB regulated Field Services Division	1	2	(7)
Foothills	10	9	9
Empire State Pipeline	6	8	10
Maritimes & Northeast Pipeline	14	18	9
Alliance Pipeline	36	20	4
Vector Pipeline	9	1	—
Merchant Capacity	(2)	—	—
Other	5	3	(1)
	188	154	128

The increase in the contribution to net earnings for Transmission & Field Services in 2000 over 1999 and 1998 is primarily due to the Alliance Pipeline and the Vector Pipeline which began operations in late 2000. Increased capital spending and a higher level of investment in these projects contributed to an increase in the amount of Allowance for Funds Used During Construction (AFUDC) recorded. Fiscal 2000 results also reflect a higher contribution from the British Columbia Pipeline and Field Services divisions as a result of higher firm contract and interruptible service revenues, partially attributable to strong natural gas prices. Fiscal 1999 net earnings, when compared with 1998, reflected the AFUDC recorded on Maritimes & Northeast Pipeline and Alliance Pipeline. The 1998 results were impacted by the $7 million after-tax write-off of an investment in a small, unregulated natural gas processing plant.

British Columbia Pipeline and Field Services Divisions

The Company's integrated natural gas gathering, processing and transmission system in British Columbia, Alberta, and the Yukon and Northwest Territories consists of approximately 5,400 kilometres of natural gas gathering and transmission pipelines and five gas processing facilities, three of which include sulphur recovery plants. These processing facilities are regulated by the National Energy Board (NEB).

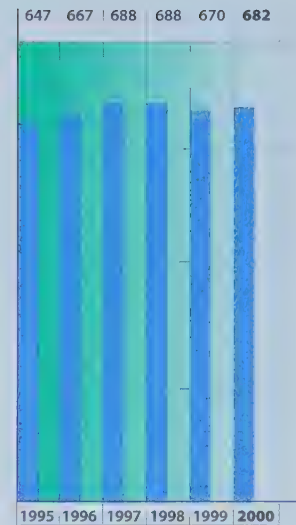
The majority of the Transmission & Field Services segment's net earnings continue to be generated from the British Columbia Pipeline and Field Services divisions. These record results for the B.C. operations are the result of increased supply from northeast British Columbia and southern Northwest Territories and strong demand from markets in the B.C. Lower Mainland and the U.S. Pacific Northwest. The British Columbia Pipeline and Field Services divisions operate under the multi-year incentive toll settlement, which was approved by the NEB in 1997. Under the multi-year incentive toll settlement gathering and processing tolls are partially indexed to natural gas prices in representative market areas served by natural gas transported through the system. As a result of increasing gas prices, demand toll revenues in 2000 increased $16 million when compared with 1999, and increased $13 million in 1999 over 1998. In 2000, higher earnings also reflected increased firm contract and interruptible service revenues, which were partially offset by higher operating and maintenance expenses. In 1999, the increase in revenues associated with higher gas prices was more than offset by lower contract demand revenues in the Field Services Division, and higher operating and maintenance costs, mainly as a result of a scheduled outage at the McMahon Cogeneration Plant. The return on common equity realized by these divisions was 13.57% in 2000, compared with 11.51% in 1999 and 12.95% in 1998.

Natural gas is delivered to markets in British Columbia, other parts of Canada and the western United States. Total throughput on the transmission mainline in 2000 was 682 billion cubic feet (Bcf), compared with 670 Bcf in 1999 and the record level of 688 Bcf achieved in 1998. The lower volumes in 1999 were largely due to reduced demand as a result of warmer weather.

Multi-Year Incentive Toll Settlement

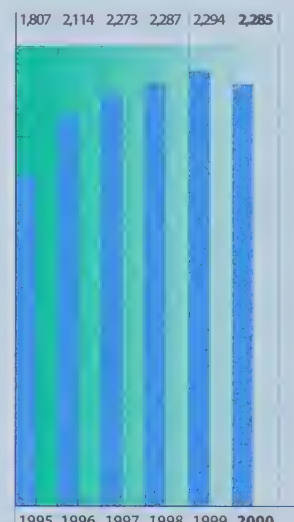
The British Columbia Pipeline Division operates under the multi-year incentive toll settlement which is effective from 1997 to December 2001. The settlement provided transmission customers a one-time option of contracting for fixed tolls for a contract term of 5 years, or tolls that are adjusted annually in accordance with a prescribed incentive methodology. Fixed tolls for 5-year service were based on a 10.67% return on common equity. Approximately 70% of the customers contracting for firm transmission service elected the 5-year fixed toll option. The Company has commenced discussions with its customers and other stakeholders concerning the transmission tolls to be charged for the period following December 31, 2001.

The multi-year incentive toll settlement provided gathering and processing shippers the one-time option of contracting for fixed base tolls for 1, 3, or 5-year service. The base tolls reflect a 500 basis point reduction from the NEB prescribed rate of return on common equity for 1997 of 10.67% and are subject to a monthly surcharge based on an index of monthly gas prices. The gas price sensitive monthly surcharge allows the Company the opportunity to earn additional revenue when gas prices are in a band between US$1.35 and US$2.00 per million British Thermal Units (MMBtu). Under the framework for light-



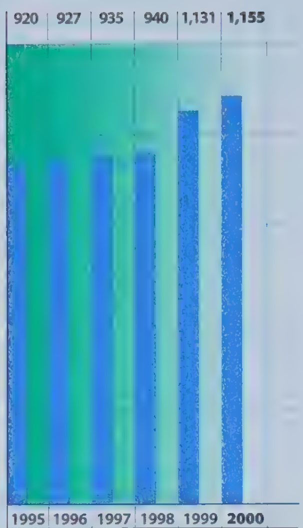
BC Pipeline Division Volumes

billion cubic feet



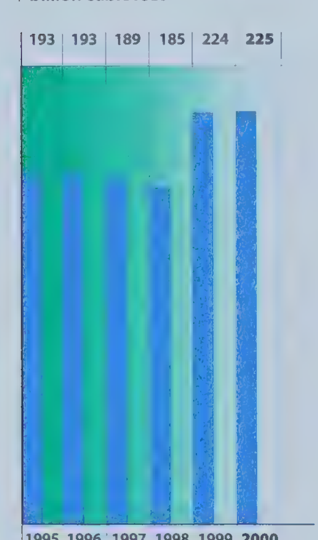
BC Pipeline and Field Services Divisions Average Rate Bases

$million



Foothills Pipe Lines Volumes

billion cubic feet



Foothills Pipe Lines Average Rate Base

proportionate share / $million

handed regulation described below, the Company and its customers are to negotiate replacement contracts as the business need arises or as the 1, 3, or 5-year tolls expire. Total revenues under these negotiated contracts are expected to be sufficient to recover the cost of providing such service, including an appropriate return to shareholders.

The multi-year incentive toll settlement was subject to agreement by the Company and its customers and other stakeholders on the principles of light-handed regulation applicable to the Company's gathering and processing services. In January 1998, the Company and its stakeholders agreed to a framework for light-handed regulation. This framework became effective immediately upon its approval by the NEB in June 1998. The framework defines the principles under which the Company negotiates individual service contracts with shippers for gathering and processing services, including the tolls applicable to such services. Consistent with these principles, the Company bears the risk for the utilization of its gathering and processing assets.

Contractual Developments

In September 2000, the Company extended the deadlines for its customers to provide notice to renew service agreements expiring October 31, 2001 relating to firm transportation service on the Southern mainline from Compressor Station 2 to Sumas and on the Fort Nelson and Fort St. John mainlines. As of November 1, 2000, substantially all of the firm transportation service on the Southern mainline and the Fort Nelson mainline has been contracted. Approximately 15% by volume of transportation service on the Southern mainline is subject to renewal effective November 1, 2002 and the balance at varying terms thereafter. The Company is investigating options for expansion of pipeline capacity from Compressor Station 2 to Sumas as well as on the Fort Nelson mainline.

As of November 1, 2000, approximately 80% of the contracts by volume of the total processing capacity were contracted on a firm basis. Approximately 40% of the contracts by volume of the total gathering and processing capacity are subject to renewal effective November 1, 2001 and contract negotiations with these gathering and processing customers are ongoing. Demand for gathering and processing services in the Fort Nelson and Grizzly Valley areas of British Columbia continues to grow. There is currently an excess of gathering and processing capacity in the Fort St. John area. In an effort to improve the profitability of its Fort St. John assets, the Company is implementing a project to rationalize the processing capacity in the area and improve facility utilization.

Non-NEB Regulated Field Services Division

Westcoast Gas Services Inc. owns interests in four provincially regulated natural gas processing plants and one liquids pipeline system.

In 1998, the Company wrote off its investment in the Buckinghorse natural gas processing plant due to low drilling activity and natural gas production in the area served by the plant, resulting in a reduction of net earnings of $7 million.

Foothills

The Company has a 50% interest in Foothills, which, through subsidiaries, transports Canadian natural gas to markets in the United States through portions of the pre-built (Phase 1) Canadian segment of the Alaska Natural Gas Transportation System. Earnings in 2000 were positively impacted by a higher rate base and a higher NEB determined return on equity.

The NEB approved return on equity for 2001 is 9.61%, compared with 9.90% in 2000. The common equity component of rate base remains at 30%.

Empire State Pipeline

The Company has a 50% interest in the Empire State Pipeline (Empire), located in upper New York State, which indirectly connects the natural gas transportation and storage facilities of Union Gas in Ontario with markets in upper New York State. Lower earnings in 2000 are the result of lower interruptible revenues due to delays in the completion of the Pendleton interconnect and downstream operating constraints at the Lysander interconnect. Higher earnings in 1998 can be attributed to a stronger United States dollar and the payment received on the cancellation of a transportation contract by one shipper. The capacity related to this contract has been substantially replaced with new firm or interruptible contracts.

In January 1997, the New York Public Service Commission approved new tolls effective November 1, 1996, which included a 12.5% rate of return on common equity, and maintained the common equity component of rate base at 40%. The tolls are based on a 7-year average rate base of $214 million. Empire achieved this rate of return and common equity component for 1999. In 2000, the pipeline earned less than the awarded return, primarily as a result of lower interruptible revenues.

In November 2000, the Company entered into an agreement to purchase the additional 50% interest in Empire, increasing its interest to 100%, for a purchase price of US$75 million. The acquisition is subject to final regulatory approval and is expected to be completed in the first quarter of 2001.

Maritimes & Northeast Pipeline

The Company has a 37.5% interest in the Maritimes & Northeast Pipeline (M&NP), which transports in excess of 500,000 MMBtu per day of natural gas sourced from offshore fields near Sable Island to markets in Nova Scotia, New Brunswick and the northeast United States. The 1,051-kilometre main pipeline and associated lateral pipelines cost approximately $2 billion. M&NP went into service on December 1, 1999 and received the first shipment of natural gas on December 31, 1999. The Company's share of M&NP net earnings was $14 million in 2000, compared with $18 million and $9 million in 1999 and 1998, respectively.

In September 2000, the NEB issued its decision regarding M&NP's application for final tolls for the 10-month period ending September 30, 2000. In its decision, the NEB disallowed certain items for inclusion in M&NP's approved rate base. As a result of the disallowance, the Company recorded a one-time negative net income impact of approximately $5 million after tax in the third quarter of 2000. An application to the NEB will be made by M&NP for rates for the period beginning October 1, 2000. Currently, M&NP is operating on interim rates.

M&NP currently has contracted firm service agreements totalling approximately 530,000 MMBtu per day. The Halifax and Saint John lateral pipelines began operation on November 1, 2000 and November 29, 2000, respectively. Application has been made to the NEB for inclusion of these pipelines in rate base.

M&NP has also commenced construction of facilities to connect its system to that of a local distributor in New Brunswick. In the first quarter of 2001, M&NP received NEB approval for the construction of facilities to serve a Nova Scotia distributor.

In August 2000, M&NP received approval from the NEB to operate the Point Tupper Lateral. Approval was granted on the condition that the line operate at approximately 50% of the originally applied for maximum operating pressure. M&NP is finalizing discussions with the pipeline builder and current owner, Sable Offshore Energy Inc., regarding transfer of ownership of the line at the reduced level of operating capacity. NEB approval for the construction of a pressure reducing station is expected in the first quarter of 2001. The Point Tupper Lateral is expected to begin service in the second quarter of 2001.

Alliance Pipeline

The Alliance Pipeline (Alliance), in which the Company has a 23.6% equity interest, has a transportation capacity of 1.3 Bcf per day of natural gas from Western Canada to the Chicago area and is fully contracted by shippers. Capital costs (including AFUDC) for the 3,686-kilometre pipeline were $5.3 billion.

Alliance began operation on December 1, 2000. Equity earnings, related to the investment in Alliance, primarily from the recording of AFUDC and from operating earnings for the month of December 2000, were $36 million in 2000, an increase of $16 million and $32 million over 1999 and 1998, respectively. This investment is a major contributor to the higher earnings experienced by the Transmission & Field Services segment.

Vector Pipeline

The Company purchased a 30% equity interest in the Vector Pipeline (Vector) during 1999. Vector connects with Alliance and other natural gas transmission systems near Chicago, and at its eastern end connects with the Union Gas Dawn-Trafalgar pipeline system and potentially with the proposed Millennium West Pipeline Project at the Dawn hub. Vector serves markets in Indiana, Michigan and Ontario and, through connecting pipelines, other markets in Eastern Canada and the northeast regions of the United States.

Vector began operation on December 1, 2000 with an initial capacity of 700 million cubic feet per day (MMcf/d). Vector capacity will increase to 1 Bcf per day following completion of the Highland compressor station in late 2001. The Company's interest in Vector contributed earnings of approximately $9 million in 2000, primarily from the recording of AFUDC and from operating earnings for the month of December 2000, compared with $1 million in 1999 from AFUDC.

Due primarily to adverse weather conditions encountered during the construction period, the total capital costs of Vector, including AFUDC, are now estimated in the US$665 million range, which will result in Vector earning less than its approved cost of capital.

Merchant Capacity

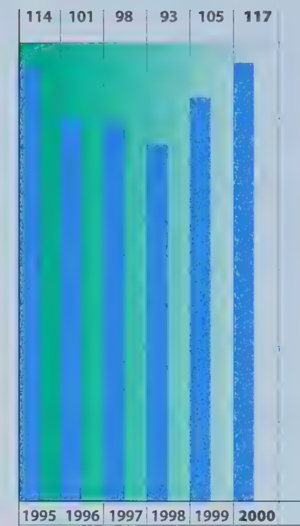
Union Gas has subscribed for 80 MMcf/d of long-term capacity for its own requirements on both Alliance and Vector. In addition, as part of the acquisition of its ownership interests in Alliance and Vector, the Company assumed a long-term capacity commitment for 66 MMcf/d and 160 MMcf/d on Alliance and Vector, respectively. Alliance and Vector merchant capacity losses totalled $2 million for the month of December 2000. The Company's capacity commitments on Alliance and Vector are currently expected to cost more than the market value of the transportation in the near term and therefore are expected to generate losses until market conditions improve. Physical and financial hedges are in place for all of the merchant capacity through October 2001 and for a portion of the merchant capacity through to October 2003.

Aux Sable Liquids Facility

The Aux Sable Chicago area natural gas liquids recovery facility (Aux Sable) associated with Alliance, in which the Company has a 23.6% equity interest, cost an estimated $690 million to construct. Aux Sable began operations in December 2000. As a result of previously established commodity hedges, results for 2000 were approximately break-even. Profitability of the project is highly dependent on the relationship between natural gas prices and natural gas liquids prices. This relationship tends to be very volatile. Under the current natural gas liquids market conditions, the Company does not expect to obtain a satisfactory return on this investment in the immediate future.

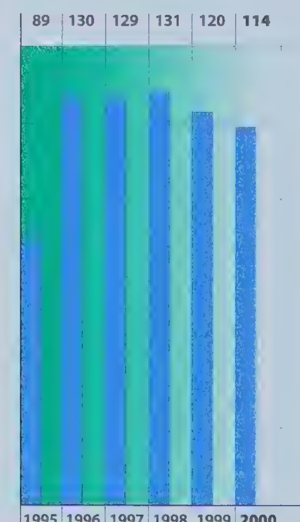
Transmission & Field Services Outlook

Demand forecasts for natural gas in North America indicate continued growth in demand, both in Canada and the United States. Natural gas reserves in North America, including the Mackenzie Delta, Alaska North Slope and the Scotian Shelf, are felt to be sufficient to meet the forecast demand growth over the longer term. The Company's processing and transmission assets are well positioned to benefit from increased supply from the



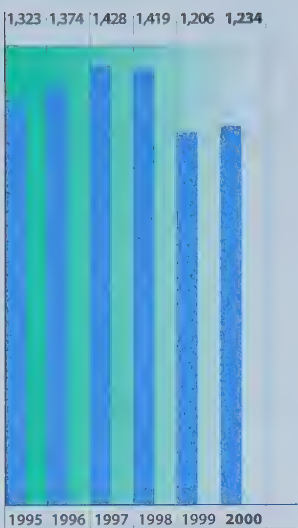
Empire State Pipeline Volumes

billion cubic feet



Empire State Pipeline Average Rate Base

proportionate share / $million



Gas Distribution Customers(1)

thousand

(1) includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively

traditional Western Canada Sedimentary Basin, southern Northwest Territories and East Coast Offshore. Growth in demand for natural gas is forecast to be generated by continued economic expansion and increased penetration of existing markets.

Competition

The Company's gathering and processing facilities in northeast British Columbia continue to be exposed to competition. The forecasted increased growth in demand for natural gas throughout North America, the current high level of exploration and development activity in the Company's service area, and the Company's ability to negotiate flexible service agreements with shippers should allow the Company to compete effectively.

During 2000, the completion of Alliance, taking gas from northeast British Columbia, and the Southern Crossing Pipeline, capable of delivering gas into southern British Columbia, introduced additional competition for the Company's Southern mainline transmission facilities in British Columbia. Despite this increase in competition, the mainline transmission facilities were fully contracted in the fourth quarter of 2000 and all available capacity on the Company's transmission mainline from Compressor Station 2 to the Huntingdon/Sumas market hub has been contracted on a firm basis to customers or affiliates through October 31, 2003.

GAS DISTRIBUTION

The contribution to net earnings for Gas Distribution was:

Years ended December 31 ($million)	2000	1999	1998
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES			
Union Gas	97	79	97
Centra Gas British Columbia	14	12	12
Pacific Northern Gas	3	3	3
Centra Gas Manitoba	—	65(1)	(4)
Centra Gas Alberta	—	—	16(2)
Other	(2)	(5)	(2)
	112	154	122

(1) includes an after-tax gain of $59 million on the sale of Centra Gas Manitoba
(2) includes an after-tax gain of $14 million on the sale of Centra Gas Alberta

Annual results include divestitures in 1999 and 1998, and a Centra Gas Manitoba regulatory decision in 1998.

Earnings in this segment were higher in 1999 than they were in 2000 primarily due to the sale of Centra Gas Manitoba in July 1999, which resulted in an after-tax gain to the Company of $59 million. Centra Gas Manitoba also contributed $6 million in earnings from operations for the seven months ended July 1999. In addition to this sale, net earnings for 1999 reflect an investment loss provision related to natural gas vehicle operations and restructuring costs resulting from business transformation initiatives at Union Gas. Fiscal 1998 results were impacted by the $14 million after-tax gain on the sale of Centra Gas Alberta. An unusual charge of $12 million was recorded in 1998 to reflect the regulatory disallowance of certain natural gas costs incurred by Centra Gas Manitoba related to price management activities.

The gas distribution businesses are sensitive to variations from normal weather conditions. Colder than normal weather conditions produce higher revenues and earnings, with the opposite result occurring in warmer than normal weather conditions. Although the weather in 2000 and 1999 was warmer than normal, fiscal 2000 and 1999 experienced higher earnings when compared with 1998 partially as a result of comparatively colder weather. In 2000, 1999 and 1998, earnings were reduced by $5 million ($0.04 per common share), $17 million ($0.15 per common share) and $39 million ($0.37 per common share), respectively, due to warmer than normal weather.

Periods of warm weather have an adverse impact on revenues which is partially offset by the opportunities created for Union Gas storage and transportation activities. A portion of revenues at Union Gas are associated with industrial customers who use natural gas for their processes and are therefore not weather sensitive.

Excluding the impact of weather and adjusting for the gain on sale of Centra Gas Manitoba noted above, net earnings from the gas distribution businesses in 2000 were $117 million compared with $112 million in 1999 and $161 million in 1998. The 2000 results reflect growth in the number of natural gas distribution customers and higher storage and transportation revenues. The reduction in earnings in 1999 reflects the January 1, 1999 transfer of assets related to Union Gas' retail merchandise and service programs to affiliates, with these earnings now reflected in the Services segment, and lower allowed rates of return on common equity for all of our gas distribution businesses. Earnings in 1999 also include an unusual expense related to business transformation initiatives.

The allowed rates of return on common equity are determined in each province by the respective provincial regulatory authority. Some of these rates of return are set by a formula that is based on a forecast of long Canada bond rates. The rates of return on common equity and the common equity components of the respective rate bases of the regulated businesses for 1998 to 2000 are outlined in Note 1 to the consolidated financial statements.

The Company's gas distribution businesses are highly seasonal, with the majority of natural gas deliveries occurring during the winter heating season from mid-October to mid-April. Gas sales during this period typically account for approximately two-thirds of annual gas distribution revenues, resulting in strong first quarter results, second and third quarters that show either small profits or losses, and strong fourth quarter results.

Over the last 18 months, the average cost of natural gas has increased substantially. The gas distribution businesses charge the purchase cost of gas directly through to customers. The natural gas cost increases may result in decreased demand for natural gas from all customer segments.

The high price of natural gas has also increased the working capital financing requirements and related costs for accounts receivable and gas inventory and may give rise to higher bad debt costs.

Natural gas volumes delivered by the gas distribution businesses were:

Years ended December 31 (Bcf)	2000	1999	1998
VOLUMES			
Union Gas	1,263	1,222	1,127
Centra Gas British Columbia	26	26	23
Pacific Northern Gas	31	39	36
Other	15	15	11
	1,335	1,302	1,197
Centra Gas Manitoba	—	42 (1)	63
Centra Gas Alberta	—	—	6 (2)
	1,335	1,344	1,266

(1) includes volumes until sold in July 1999
(2) includes volumes until sold in June 1998

The number of customers for the gas distribution businesses were:

As at December 31 (thousand)	2000	1999	1998
NUMBER OF CUSTOMERS			
Union Gas	1,123	1,099	1,075
Centra Gas British Columbia	69	66	61
Pacific Northern Gas	40	39	39
Other	2	2	2
	1,234	1,206	1,177
Centra Gas Manitoba (1)	—	—	242
	1,234	1,206	1,419

(1) sold July 1999

Union Gas

Union Gas distributes natural gas in Ontario. It also transports and stores natural gas for customers in Ontario, Quebec and the central and eastern United States. Union Gas' underground natural gas storage facilities have a working capacity of 143 Bcf and are the largest in Canada.

Following Ontario Energy Board (OEB) approval in May 1998, Union Gas transferred the operating responsibilities of its retail merchandise and service programs to Union Energy, an affiliated, non-regulated retail energy services business. This transfer occurred on January 1, 1999 when approximately $500 million of net assets were acquired by Union Energy. The transferred retail merchandise and service programs include appliance sales and rentals, appliance service work and merchandise financing. Union Energy, as a non-regulated business, has more flexibility and geographic reach than the regulated utility to design and package energy products and services to meet customer needs. Union Gas continues to concentrate on developing and operating new services that emphasize cost effectiveness and reliability in the delivery of natural gas to customers.

Results in 2000 continued to be adversely affected by warmer than normal weather for the third consecutive year. Weather reduced earnings by $5 million, $14 million and $35 million in 2000, 1999 and 1998, respectively. The increase in 2000 earnings compared with 1999 is primarily related to customer growth and higher storage and transportation revenues. The decrease in 1999 earnings compared with 1998 is primarily due to the transfer of the retail merchandise programs of Union Gas to Union Energy ($18 million), and a lower allowed rate of return on common equity ($9 million). Earnings in 1999 also include an expense related to business transformation initiatives.

The average amount of natural gas consumed by Union Gas residential customers declined again this year. This decline is caused primarily by the replacement of older heating equipment by newer, more efficient equipment, and by more energy-efficient housing.

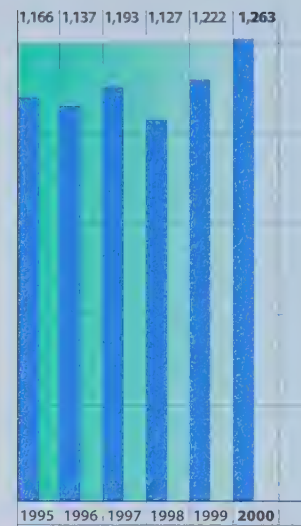
Performance-Based Regulation

In March 1999, Union Gas filed an application with the OEB for approval of new rates that would be in accordance with a Performance-Based Regulation (PBR) mechanism, to be effective January 1, 2000 for a five-year period. This mechanism, known as a price cap, is proposed to fix the annual unit rate increases for regulated services at 1.9%. There is some pricing flexibility allowed, including the ability to negotiate longer-term rates with customers. Certain items, such as the cost of purchasing gas, will continue to be passed through to customers at cost, the same treatment as currently exists under cost of service regulation. Under the proposal, Union Gas is prepared to accept somewhat more risk than it would otherwise under the current cost of service regulation. The OEB held a hearing on the PBR application during the second and third quarters of 2000 and arguments were completed in August 2000. A decision is expected in the first quarter of 2001.

Centra Gas British Columbia

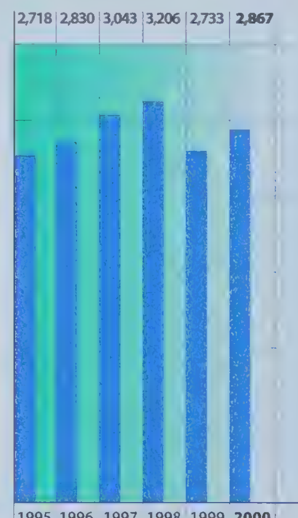
In December 1995, the Company and the Province of British Columbia entered into an agreement replacing the previous financial arrangements relating to the natural gas pipeline to Vancouver Island and connected distribution systems owned by Centra Gas British Columbia Inc. (Centra Gas BC).

For the years 1996 to 2002, the agreement provides for a deemed common equity component of rate base of 35% and a return on the common equity component of rate base of 3.625% over the Government of Canada long term bond rate. The agreement also provides for a reduction in the return on equity of approximately $2 million per year for the years 1996 to 2011. For 2000, Centra Gas BC's effective rate of return on common equity was 8.4%, compared with 7.8% in 1999. The increase in earnings in 2000 is primarily due to a higher rate base and a higher allowed rate of return on common equity. Centra Gas BC increased its customer base by 4.5% in 2000 over 1999. Increased royalty revenues, combined with effective management of gas supply costs, have resulted in the revenue deficiency incurred in 2000 under the existing regulatory framework being lower than it otherwise would have been. The cumulative revenue deficiency under the existing regulatory framework was approximately $73 million at the end of 2000.



Union Gas(1) Volumes

billion cubic feet

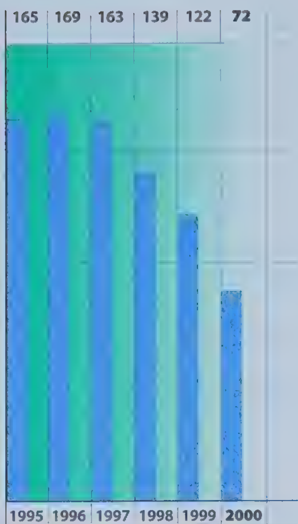


Union Gas(1)(2) Average Rate Base

$million

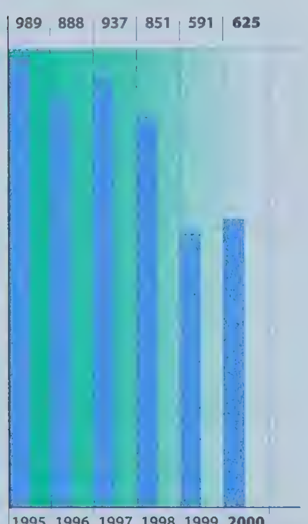
(1) includes Centra Gas Ontario Inc. which was amalgamated with Union Gas effective January 1, 1998

(2) On January 1, 1999, Union Gas transferred approximately $500 million of net assets to Union Energy



Other Gas Distribution Volumes(1)

billion cubic feet



Other Gas Distribution Average Rate Bases(1)

$million

(1) includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively

The British Columbia Utilities Commission (BCUC) commenced a process in January 2000 to establish the long term cost allocation and rate design principles that Centra Gas BC will employ commencing in 2003. Approval to recover the revenue deficiency will be sought from the BCUC over as short a period as possible, while balancing the impacts on customer rates and the continued need to provide a competitively priced service.

Pacific Northern Gas

Pacific Northern Gas Ltd. (PNG) delivers gas to customers in west-central British Columbia and through its subsidiary, Pacific Northern Gas (N.E.) Ltd., to customers in the province's northeast. Four large industrial customers in the petrochemical, pulp and aluminum businesses accounted for approximately 64% of total gas deliveries in 2000.

The rate of return on common equity for PNG, as determined by a formula approved by the BCUC, was 10.25% for 2000, compared with 10.00% for 1999, on a deemed common equity component of rate base of 36%.

In May 2000, PNG was advised by Methanex Corporation (Methanex) of its decision to shut down the Kitimat methanol/ammonia plant for an initial period of 12 months commencing July 1, 2000. Methanex is PNG's largest customer and accounted for 43% of volumes transported in 2000 and 40% of operating margin. PNG's 2000 earnings were not affected by the plant shutdown due to three firm gas transportation service agreements with Methanex which contain take or pay obligations for up to 80% of the respective contract demand and due to a BCUC approved deferral account. The largest of these contracts with Methanex, representing approximately 77% of the total Methanex contract demand, expires on October 31, 2002.

The uncertainty relating to deliveries to Methanex have made it difficult for PNG to raise capital on acceptable terms. Furthermore, PNG has been required by its lender to reduce its operating line. In response to this situation PNG has developed strategies to preserve capital and reduce operating costs. An application has been presented to the BCUC to seek regulatory relief.

The Company's current investment in PNG is approximately $27 million.

Centra Gas Manitoba

In July 1999, the Company sold Centra Gas Manitoba to Manitoba Hydro for $245 million, resulting in an after-tax contribution to net income of $59 million, or $0.52 per common share. Consequently, earnings for 1999 include the earnings of Centra Gas Manitoba to the date of completion of the sale. Earnings in 1998 reflect the non-recurring impact of the MPUB decision to disallow the recovery of certain natural gas costs related to price management activities. In June 1998, the MPUB approved the recovery of $19 million and disallowed the recovery of $27 million of approximately $46 million of natural gas costs related to price management activities. Of the $27 million of disallowed natural gas costs, $9 million was recovered from brokers serving the direct purchase market.

The impact of the disallowance, net of recoveries, related items and income taxes, is a net reduction to 1998 earnings of approximately $12 million, or $0.12 per common share.

Centra Gas Alberta

In June 1998, the Company sold Centra Gas Alberta to AltaGas Services Inc. for $61 million, resulting in an after-tax contribution to net income of $14 million or $0.14 per common share.

Gas Distribution Statistics

The average rate bases for the gas distribution businesses were:

Years ending December 31 ($million)	2000	1999
RATE BASE		
Union Gas	2,867	2,733
Centra Gas BC	429	400
PNG	172	170
Other	24	21
	3,492	3,324

POWER GENERATION

The Company has interests in five operating natural gas fired cogeneration plants in Canada and is developing additional projects.

The contribution to net earnings for Power Generation was:

Years ended December 31 ($million)	2000	1999	1998
NET INCOME APPLICABLE TO COMMON SHARES	16	11	6

The increase in earnings in 2000 compared with 1999 is primarily due to revenue from the resale of gas at the McMahon Cogeneration Plant and the Lake Superior Cogeneration Plant and effective utilization of power transmission capacity in New England acquired in anticipation of the Bayside Power Project. Fiscal 2000 results also include a $3 million after-tax gain on the sale of the Company's 50% interest in the Liberty Electric Power Project. The 1999 results included a $3 million after-tax gain on the sale of the Company's 50% interest in the Fort Nelson powerline.

The lower contribution to net earnings for Power Generation in 1998 was primarily due to the shutdown of the Fort Frances Cogeneration Plant due to a labour strike at Abitibi-Consolidated Inc., the steam host facility.

In September 2000, Westcoast Energy entered into a letter of intent to sell its interests in four older operating power generation assets and the 100%-owned Island Cogeneration Project (ICP) currently under construction. Significant changes in the power and natural gas markets since the signing of this letter of intent have complicated the transaction. While negotiations are continuing, the outcome of these negotiations is uncertain. In the interim, strong market conditions have resulted in continued good performance of these assets.

Demand for electric power continues to grow in North America and, in particular, in or near markets currently served by the Company's natural gas pipeline

assets. As the power industry continues to deregulate, the commercial risk to which power producers will be exposed will continue to increase. Companies with power generating assets will be required to accept more merchant risk in power markets. The Company will continue to develop generation projects through investments in Canada and the United States.

Engage Energy, the Company's marketing and trading affiliate, is working with Westcoast Power to assist in managing merchant power risk related to the Bayside Power Project, Frederickson Power Project and future projects.

Island Cogeneration Project

In September 2000, ICP completed construction and began commissioning of the $240-million 250-megawatt (MW) natural gas fired cogeneration unit, located at Norske Skog Canada's pulp and paper mill near Campbell River on Vancouver Island, British Columbia. The engineering, procurement and construction (EPC) contractor and turbine supplier for ICP has advised that required design changes to the turbine and difficulties with plant commissioning will delay the start-up of the project. As well, distillate firing capability, intended to be available at start-up, will be further delayed but will not prevent interim operations on natural gas. Current contractual arrangements require the EPC contractor to make certain payments to ICP as a result of these delays and the expected reduction in plant output and efficiency. ICP is currently in discussions with the EPC contractor regarding amendments to the existing contractual arrangements intended to facilitate interim operations of the plant. ICP anticipates that interim operations will begin early in the second quarter of 2001 with completion delayed until 2002.

Bayside Power Project

The Bayside Power Project is repowering an existing 100 MW heavy fuel oil fired generating plant located in Saint John, New Brunswick into a natural gas fired combined cycle plant with a design capacity of 285 MW. The project is anticipated to cost approximately $165 million to construct. The project is over 90% complete and is now scheduled for a commercial in-service date late in the second quarter of 2001 due to ongoing project execution challenges faced by the EPC contractor and turbine supplier for the project. Current contractual arrangements require the EPC contractor to make certain payments to Bayside Power Project as a result of these delays.

In August 2000, the Company sold 25% of its interest in the wholly owned Bayside Power Project for approximately $32 million and an option to participate in future site development under rights held by Irving Oil. The proceeds approximated net book value.

Frederickson Power Project

Frederickson Power and the Bonneville Power Administration have entered into an agreement under which Frederickson Power has purchased, at a cost of US$25 million, a partially built and fully permitted 249-MW natural gas fired electricity generation project located between Tacoma and Olympia in the State of Washington. Gas turbine and steam turbine equipment has been secured and engineering and preliminary construction activities have commenced. The current plan calls for the electricity generating facility to begin operations in mid-2002 with estimated capital costs of $260 million.

In May 2000, the Company sold 40% of its interest in the wholly owned Frederickson Power Project. The proceeds approximated net book value.

Liberty Electric Power Project

In February 2000, the Company sold its 50% interest in the proposed 500-MW Liberty Electric Power Project near Philadelphia, Pennsylvania, to Columbia Electric, the primary developer of the project, for $13 million, resulting in an after-tax gain of $3 million.

INTERNATIONAL

The operating businesses included in this business segment are power generation facilities located in Irian Jaya, Indonesia and Shanghai, China, as well as two projects in Mexico.

The contribution to net earnings for International was:

Years ended December 31 ($million)	2000	1999	1998
NET INCOME APPLICABLE TO COMMON SHARES	29	15	16

Included in the fiscal 2000 results is the $8 million after-tax gain on the sale of the Company's 74% interest in the EastCoast Power Project in Australia, offset by deferred income tax expense of $13 million arising from inflationary gains and the relative strength of the Mexican peso against the U.S. dollar. In addition, the income contribution from the P.T. Puncakjaya Power facilities investment increased due to increased capacity revenues and lower interest costs. Results in 1998 include the $8 million after-tax gain on the sale of the Company's interest in the Australian Eastern Gas Pipeline Project.

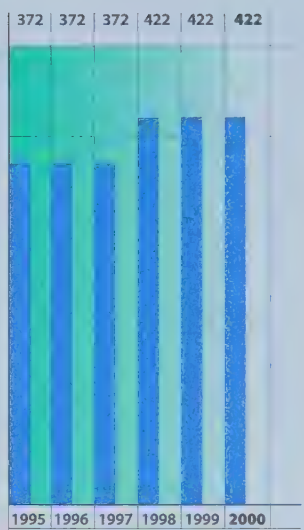
The contributions from the two Mexican projects will continue to be impacted by deferred income taxes, which are dependent on the relative value of the Mexican peso to the U.S. dollar against the Mexican inflation rate.

Given the opportunities available to the Company in North America, the Company is now focusing its international development activities on the Mexican energy sector.

Indonesia - Irian Jaya Power Plant

The Company has a 43% interest in P.T. Puncakjaya Power (PJP) which owns and operates approximately 388 MW of power generation capacity, a related transmission line and associated facilities providing electrical power to the Grasberg mine under a long-term contract.

Payments to PJP are denominated in United States dollars and are payable in the United States. The Company is therefore effectively sheltered from fluctuations in the value of the Indonesian currency. The mine, operated by



Power Generation Plant Capacity

megawatts

PT Freeport Indonesia, is a low-cost producer of copper and also produces gold.

Although Indonesia suffers from periodic political unrest, the mine, which is in a remote part of Indonesia, is a major contributor to the economy in the form of taxes and employment, and its operations have not been affected by recent events.

Mexico – Cantarell Nitrogen Facilities

The Company has a 20% interest in the Cantarell Nitrogen Facilities. The facilities, which cost $1.5 billion, sell nitrogen under a long-term take or pay agreement with Pemex Exploración y Producción (PEP), a subsidiary of the national oil company of Mexico, to enhance the production and recovery of oil from the Cantarell oil field located in the Bay of Campeche, Gulf of Mexico. The nitrogen supply contract with PEP provides for fixed capacity payments in United States dollars.

Performance testing of the Cantarell Nitrogen Facilities was completed in December. The plant is in operation and has delivered to PEP the design capacity of 1,200 MMcf/d of nitrogen production.

Limited recourse financing for $935 million of the $1.5-billion total project cost was secured in September 1999. As of February 1, 2001, the shareholders have contributed $531 million to the Cantarell Nitrogen Facilities. The Company's share of this investment is $115 million.

Mexico – Campeche Natural Gas Compression Services Project

In August 1998, an international consortium, in which the Company has a 45% interest, was awarded a 5-year take or pay contract by PEP to provide 250 MMcf/d of offshore natural gas compression and liquids recovery services on a platform in the Cantarell oil field in the Bay of Campeche, Gulf of Mexico. The consortium is constructing and will own and operate the platform which has an estimated cost of $410 million. The fixed capacity charge payable by PEP under the take or pay contract is payable in United States dollars.

The project has experienced construction delays due to weather-related problems and difficulties with the local contractor. While contractually the project is subject to penalties for late completion, a series of formal requests have been made to PEP to extend the contract in-service date. Formal contract extension has been agreed to by PEP on the first of these requests, extending the in-service date on a no-fault basis to September 5, 2000. The subsequent extension requests are under review by PEP. The project is expected to begin service early in the second quarter of 2001.

China – Shanghai Power Plant

The Company has a 32.5% interest in a captive power project to produce 50 MW of electrical power at the Baosteel Group Shanghai No.1 Iron & Steel Company Ltd. facilities in China. The plant, which uses waste blast furnace gas as its primary fuel, cost approximately $75 million.

The power plant commenced commercial operations on June 1, 2000, contributing net earnings of $2 million in 2000. Government approval for the transfer of project earnings and other project amounts out of China will be required. The Company has secured political risk insurance to cover its investment.

Australia – EastCoast Power Project and Eastern Gas Pipeline Project

In April 2000, the Company sold its 74% interest in the EastCoast Power Project to a subsidiary of Duke Energy for approximately $17 million, resulting in an after-tax gain of $8 million.

In December 1998, the Company sold its 50% interest in the Eastern Gas Pipeline Project to a subsidiary of Duke Energy for approximately $27 million. The disposition resulted in a contribution to 1998 net earnings of $8 million after tax.

SERVICES

Included in this business segment are businesses that provide energy marketing, retail energy services, information technology and financial services.

The contribution to net earnings for Services was:

Years ended December 31 ($million)	2000	1999	1998
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES			
Energy Marketing	35	4	(34)
Union Energy	—	(38)	(12)
Westcoast Capital	21	8	—
Enlogix	(16)	(8)	(1)
NGX	5(1)	2	1
	45	(32)	(46)

(1) includes an after-tax gain of $4 million on the sale of 51% of the Company's interest in NGX

The increase in earnings in fiscal 2000 compared with 1999 and 1998 is primarily due to a strong performance by the energy marketing business and Westcoast Capital Corporation (Westcoast Capital), and a significant improvement at Union Energy. Fiscal 2000 results also include the after-tax gain of $4 million relating to the sale of 51% of the Company's interest in NGX. Results in 1998 reflected the Company's share of an unusual loss of $14 million after tax due to customer defaults at Engage Energy and losses on firm capacity contracts related to the Kern River and Northwest pipelines.

Energy Marketing

Engage Energy contributed net earnings in 2000 of $26 million, compared with $5 million in 1999 and a net loss of $26 million in 1998. Engage Energy achieved improved results year over year from structured natural gas and power transactions, improved risk management and a continued emphasis on cost containment. The significant improvement in the 2000 results is due to the addition of new gas and electric structured projects and successful trading operations. The price volatility in the North American natural gas and electric markets in the fourth quarter of 2000 created increased opportunities for trading

and structured products.

The increase in earnings for the energy marketing business is also in part due to the sale in the second quarter of 2000 of the capacity on the Kern River Pipeline, and a portion of the associated upstream capacity on Northwest Pipeline, offset partially by a loss on the residual upstream capacity in the fourth quarter. All of the capacity on the Kern River Pipeline has now been permanently assigned to other parties, and as of the end of 2000, the Company holds only a small amount of remaining upstream capacity on Northwest Pipeline.

Results for 2000 and 1999 reflect the adoption of mark-to-market accounting, effective January 1, 1999, for the Company's energy marketing operations. The cumulative effect of the initial adoption of mark-to-market accounting at January 1, 1999, offset by the unamortized energy contracts purchased to equalize the Company's ownership in Engage Energy, was recorded as a charge totalling $36 million against retained earnings.

In October 2000, the Company and The Coastal Corporation terminated their Engage Energy joint venture and divided the operations into separate entities which will be owned and operated independently by each company. Details of the termination of the joint venture agreement are provided in Note 8 to the consolidated financial statements.

Energy Marketing Risk Management

Energy Marketing operates in a competitive environment characterized by volatility and often by narrow margins. Engage Energy operates an energy merchant and trading business, in which its portfolio of physical and financial forward transactions has inherent market, credit and operations risks. The Company's risk management policy defines the methodology to be employed in measuring risks and the maximum daily risk exposure. The risks of the Company's energy marketing portfolio are monitored by an internal Risk Management Committee independent of energy trading activities to ensure compliance with Company standards. The Company monitors and manages its exposure to market risk through a variety of risk management techniques. The Company utilizes derivative and other financial instruments to manage the impact of market fluctuations on assets, liabilities or other contractual commitments.

Union Energy

Union Energy serves 1.1 million customers and operates 45 branches providing heating, ventilating and air conditioning sales and services. In addition, Union Energy offers customers rental and financing options.

On January 1, 1999, Union Energy assumed operating responsibility for certain business and assets from Union Gas in retail merchandise and service programs. These assets relate to appliance sales and rental programs, appliance service work and merchandise financing. After a difficult start-up, Union Energy posted a loss of $38 million in 1999. Certain after-tax charges of $18 million such as the write-off of capitalized software costs, increases in bad debt reserve and inventory and computer equipment write-downs were responsible for a large portion of the weak performance.

In 2000, Union Energy operated at break even. A decrease in operating costs and significant margin improvements contributed to the improved performance of the equipment rental businesses, which offset continuing losses in the heating, cooling and fireplace business.

Westcoast Capital

Westcoast Capital was established in April 1997 to provide selected financial services to complement the Company's other product offerings. Westcoast Capital's business is largely focused on energy-related investments and is divided into two distinct sectors, Retail Finance and Structured Finance. The Retail Finance business includes the financing and rental of household appliances to individual homeowners while the Structured Finance business includes the financing of capital equipment for businesses. In order to focus on the Retail Finance business of Westcoast Capital, the Company decided in the fourth quarter of 2000 to cease doing further Structured Finance business.

Earnings in 2000 reflect growing operations and the early buyout of a gas transportation agreement in the first quarter of 2000; however, almost all of the increase is attributable to the favourable impact from substantively enacted corporate income tax rate reductions. The increase in earnings over 1998 is primarily related to the acquisition of the majority of the assets of Union Gas' retail merchandise finance and rental programs on January 1, 1999.

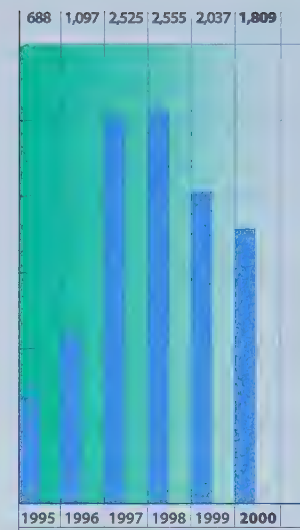
The portfolio of financial assets includes both a significant retail portfolio and a number of Structured Finance transactions. The growth of Westcoast Capital's Structured Finance portfolio continued in 2000 as the Company invested approximately $75 million in oil gathering and processing, gas compression and industrial equipment and volumetric prepayments.

In 2000, Westcoast Capital received proceeds of approximately $360 million on the securitization of rental assets and asset-backed finance contracts to WestCap Trust. WestCap Trust, established to purchase assets from Westcoast Capital, now holds, after inclusion of reserves and purchases of asset-backed finance contracts previously made in 1999, assets in excess of $380 million. The proceeds were used to reduce external borrowings.

Westcoast Capital is exposed to the risk that costs associated with funding fixed rate leasing and financing contracts will change in response to changing debt market conditions. This risk is monitored and, where deemed appropriate, various swap and hedging products are utilized to minimize losses to the portfolio of investments.

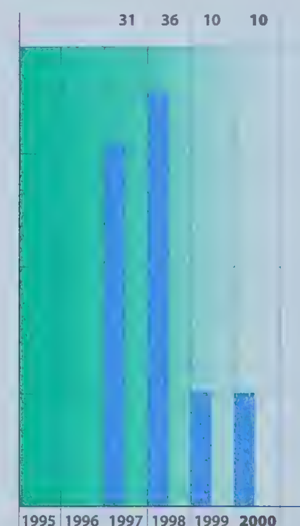
Enlogix

Enlogix Inc. (Enlogix) provides billing and customer information services to the energy and utility sectors,



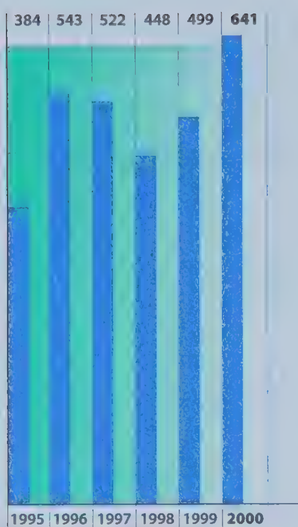
Energy Marketing Natural Gas Marketed

billion cubic feet



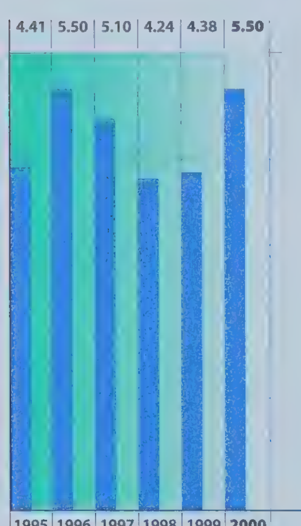
Energy Marketing Electric Power Marketed

million megawatt hours



Operating Cash Flow

$million



Operating Cash Flow per Common Share

dollars

providing 13 clients with billing services for their 3 million customers. Enlogix systems support clients in the regulated and unregulated gas, electric, water, and energy services sectors across North America. In December 2000, Enlogix completed a multi-year applications development agreement along with a comprehensive new marketing and sales agreement with SCT Utility Systems, Inc. (SCT). Enlogix customer information service is based on SCT's billing software. Enlogix expects to reach sustainable monthly break-even results on operations by the end of 2002 and has set a three-year goal of increasing its customer base to 5 million.

A net loss applicable to common shares of $16 million was incurred for the year ended December 31, 2000. Enlogix ceased capitalizing certain expenses relating to software development and commenced recording depreciation expense at the start of operations effective October 1, 1999. Consequently, the fiscal 2000 results reflect the impact of such changes. As well, Enlogix took over technical service operations from a contractor, which is expected to result in significant ongoing cost savings.

NGX

On March 31, 2000, the Company sold 51% of its natural gas exchange operation to OM Gruppen of Sweden, a European electronic exchange owner and operator, for $8 million, resulting in an after-tax gain of $4 million.

In January 2001, the Company sold its remaining 49% interest in NGX to OM Gruppen, effective January 1, 2001, for $10 million, resulting in an after-tax gain of $6 million in the first quarter of 2001.

Competition

The services group operates in a highly competitive environment and in many cases competes for business against large and well-established firms. In some cases the services group depends on technology or market lead which can be overtaken by others. To compete successfully, the services group must maintain or grow its market position, focus on cost efficiency and look to innovative product leadership.

OTHER

This business segment includes corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

The contribution to net earnings for this segment was:

Years ended December 31 ($million)	2000	1999	1998
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES			
Corporate financing	(79)	(65)	(65)
Business development	(5)	(11)	(15)
Other	34	(4)	15
	(50)	(80)	(65)

Corporate financing expenses include preferred share dividends of $48 million, $45 million and $36 million in 2000, 1999 and 1998, respectively. Unallocated interest amounted to $31 million in 2000, relating to approximately $750 million of debt, compared with $20 million in 1999, relating to approximately $800 million of debt and $29 million in 1998, relating to approximately $1,050 million of debt. Results in 1998 include a foreign exchange gain of $9 million.

As the result of a change in the accounting for income taxes, effective January 1, 2000, the deferred tax liabilities or assets are adjusted to reflect substantively enacted income tax rates. The decrease in net costs in 2000 compared with 1999 and 1998 is primarily due to the $34 million favourable impact of the corporate income tax rate reductions.

Business Development

Millennium Pipeline Projects

The Company has a 21% interest in the proposed Millennium Pipeline Project (Millennium) which is designed to deliver 700 MMcf/d of natural gas from southwest Ontario to New York City and other markets in the eastern United States. The 611-kilometre pipeline is expected to cost approximately $1 billion.

The Millennium West Pipeline Project (Millennium West), in which the Company has a 100% interest, is a proposed $172-million, 75-kilometre pipeline from Union Gas' existing pipeline system and storage facilities at the Dawn hub in Ontario to the shore of Lake Erie northwest of Patrick Point, Ontario. Millennium West is intended to interconnect with another proposed pipeline that would cross Lake Erie to connect to Millennium.

As of December 31, 2000 the Company had an investment of $17 million in these development projects. The Millennium partners continue to pursue the necessary United States regulatory approvals. In addition, for this project to proceed, long term market commitments are required to advance the project. As a result of delays in obtaining United States approvals for Millennium, Millennium West has requested and the NEB has agreed to a temporary delay in the commencement of the hearing on the project's application for NEB approval until the required United States approvals have been received for Millennium.

LIQUIDITY AND CAPITAL RESOURCES

Cash Generated from Operations

Cash generated from operations was $573 million for the year ended December 31, 2000, compared with $456 million and $502 million in 1999 and 1998, respectively. The increase in cash generated from operations in 2000 is primarily attributable to higher net income in 2000, the result of a solid performance from the British Columbia Pipeline and Field Services divisions, improved results from the services businesses, and higher contributions from international projects.

The contribution to consolidated operating cash flow after non-cash working capital changes by business segment was:

Years ended December 31 ($million)	2000	1999	1998
CASH FLOW FROM OPERATING ACTIVITIES			
Transmission & Field Services	299	238	234
Gas Distribution	285	246	283
Power Generation	32	25	25
International	77	38	30
Services	22	14	(65)
Other	(74)	(62)	(59)
Operating cash flow	641	499	448
Non-cash working capital changes	(68)	(43)	54
	573	456	502

Over the last 18 months, the average cost of natural gas has increased substantially which has resulted in increased working capital financing requirements and related costs for accounts receivable and gas inventory and may give rise to higher bad debt costs.

Investing Activities

The year 2000 represents the final year of a three-year, $4-billion capital expansion and investment program. In 2000, capital expenditures and investments totalled approximately $1.3 billion. Capital expenditures amounted to $747 million in 2000 compared with $1,305 million in 1999 and $911 million in 1998. The majority of capital spending in fiscal 2000 and 1999 is related to four projects, M&NP, Alliance, Vector and ICP, as well as Union Gas. Capital expenditures in 1998 were primarily related to higher activity with respect to projects under development such as the M&NP, the Cantarell Nitrogen Facilities and the Shanghai Power Plant.

The multi-year expansion program in which the Company has been engaged is nearing completion and capital spending is returning to more normal levels. The Company's planned capital spending program for 2001 is currently projected to total $750 million. The planned spending for 2001 is primarily for the British Columbia Pipeline and Field Services divisions, Union Gas and the Frederickson Power Project. The Company also purchased the additional 50% interest in Empire for a purchase price of US$75 million in the first quarter of 2001. The Company anticipates that most of its capital program can be met from internally generated funds.

The Company's 2000 acquisitions include the purchase of the additional 50% interest in Engage Energy Canada L.P. Acquisitions in 1999 consisted of the purchase of 13 HVAC businesses and a 30% interest in Vector, while 1998 reflects the acquisition of 15 HVAC businesses, and additional interests in Alliance and ICP. Investing activities in 2000 also reflect cash provided by the dispositions of interests in NGX, EastCoast Power Project, Bayside Power Project, Liberty Electric Power Project and Frederickson Power Project. The sale of certain rental assets and asset-backed finance contracts by Westcoast Capital provided cash proceeds of approximately $360 million in 2000. Investing activities in 1999 reflect cash provided by the disposition of Centra Gas Manitoba, the Company's interest in the Fort Nelson powerline joint venture and the sale of certain asset-backed finance contracts by Westcoast Capital. Investing activities in 1998 reflect the sale of the Company's interest in the Australian Eastern Gas Pipeline Project and Centra Gas Alberta.

Financing Activities

The Company, its subsidiaries and joint ventures have the ability to draw on operating lines of credit in excess of $1,500 million with commercial banks. These operating lines of credit enable the Company, its subsidiaries and joint ventures to borrow directly from the banks, to issue bankers' acceptances and to support commercial paper programs.

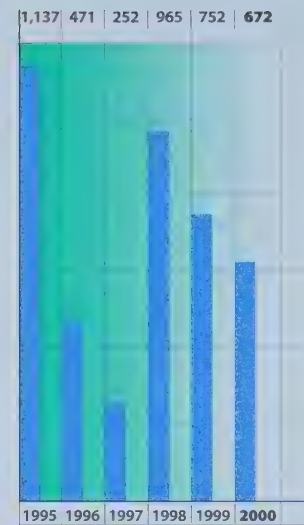
The Company, its subsidiaries and joint ventures make use of short term indebtedness to finance working capital as well as provide interim financing in advance of long term debt or equity issues. At times, the resulting consolidated short term indebtedness and the portion of long term debt due within one year result in negative working capital.

In 2000, from the issuance of long term debt and common equity and the addition of new bank facilities, the Company, its subsidiaries and joint ventures raised cash of $856 million (1999 - $1,083 million; 1998 - $1,484 million). In January 2000, the Company raised $150 million from the issue of 7.20% Medium Term Note Debentures, Series 7 and in June 2000, Union Gas raised $185 million from the issue of 7.20% Medium Term Note Debentures, Series 2. In June 2000, WEI Holdings (US) Inc., a wholly owned subsidiary of the Company, arranged a US$150-million term credit facility. In November 2000, the Company issued 4,000,000 common shares for cash under a public offering at a price of $32.25 per share, thereby increasing common stock by $129 million. The net proceeds of the common stock issuance were used to retire commercial paper previously issued by the Company, pre-fund the planned acquisition of the additional 50% interest in Empire in New York State and other corporate purposes.

The Company issues common shares through its Dividend Reinvestment and Share Purchase Plan. Common shares issued under the Plan increased common stock by $50 million in 2000 compared with $55 million in 1999 and $51 million in 1998.

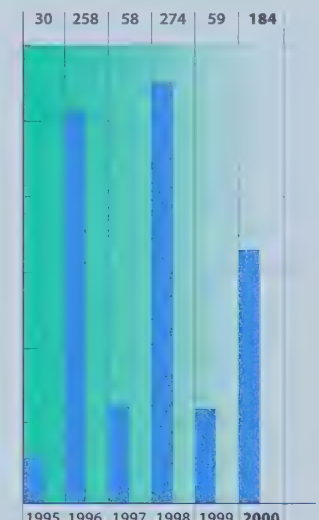
Details of long term debt, preferred share issues and common share issues are provided in Notes 2, 6, and 7, respectively, to the consolidated financial statements.

In 1999, and continuing into 2000, a concern developed about the emerging difficulty of attracting capital to the pipeline and utility sector at an appropriate cost in order to fund growth. Regulators at the federal and provincial level have, over the past few years, reduced the



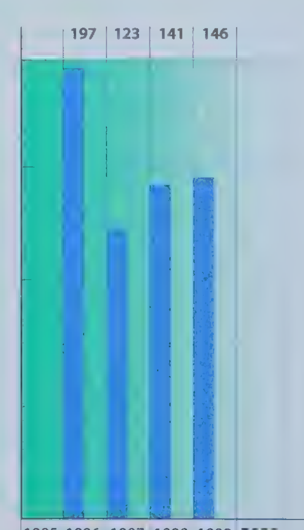
Long Term Debt Issued

$million



Common Shares Issued

$million



Preferred Shares Issued (net)

$million

approved rates of return for the regulated utility parts of the Company and its industry.

The rates of return prescribed by regulators in Canada are significantly lower than those in the United States and lower than the level believed to be necessary to attract appropriate future investment capital to the pipeline and utility sector.

NEW ACCOUNTING PRONOUNCEMENTS

Earnings Per Share

In December 2000 the CICA issued a new standard, Section 3500 of the CICA Handbook "Earnings Per Share," which brings Canadian requirements in line with U.S. standards. It requires the presentation of basic and diluted earnings per share figures for net income on the Statements of Operations. Under the new standard the treasury stock method is to be used, instead of the current imputed earnings approach, for determining the dilutive effect of warrants and options.

The new standard is effective for fiscal years beginning on or after January 1, 2001. While early adoption is permitted, the Company will adopt the standard in fiscal 2001. Comparative periods presented will be restated to conform with the above recommendations. Based on the 2000 financial results, the impact of adopting Section 3500 would result in diluted earnings per common share of $2.75, compared with $2.70 under the current standard as disclosed in Note 3 to the consolidated financial statements.

MARKET OUTLOOK

Natural gas continues to be an efficient and environmentally acceptable form of energy. The past year's increases in the market price of natural gas have caused some industrial users of gas to switch to other forms of energy or to suspend or move operations. Supply is expected to increase in response to recent price increases which will restore the competitive position of natural gas relative to other fuels. Accordingly, the demand for gas is expected to continue to grow.

Shortages of electric power in regions of Canada and the United States demonstrate a need for additional electric generating capacity. Gas fired generation is capital cost efficient, environmentally more acceptable than other alternatives and relatively faster to develop and construct. It is expected that gas fired generation will continue to be a leading source of incremental power in North America and will continue to drive growing demand for natural gas.

New energy technologies such as fuel cells, micro-turbines and other forms of distributed generation generally use natural gas as a fuel source. Further development of these technologies is expected to continue to support the use of natural gas as a primary source of energy.

The increase in market prices in the past year has been the result of slower than expected supply growth combined with strong demand growth. While additional infrastructure has been completed to support the delivery of natural gas to markets, the supply response from the traditional producing regions has been slower than originally anticipated. However, higher gas prices have resulted in increased exploration and development both in traditional producing regions and in new producing regions such as off the coast of Nova Scotia and in the southern Northwest Territories. In addition, the industry is considering the development of pipeline facilities to allow the development of large proven reserves in Alaska and potential reserves in the Mackenzie Delta. In the medium and longer term, supply of natural gas is not expected to be a limiting factor in the use of natural gas as an important energy source in North America.

In the near term, incremental pipeline infrastructure has been completed in advance of a full increase in supply. As a result, surplus pipeline capacity will exist until the gas supply response catches up to the current level of delivery capacity and demand.

The regulatory environment in Canada continues to evolve to one of less financial regulation. This evolution in regulatory direction is resulting in higher risk; however, it is also providing opportunities for higher returns and for utility companies to be more flexible in responding to competitive pressures.

The outlook for the Company's key businesses is positive as Canadian sourced gas takes on a larger share of total North American supply. The Company's assets are well situated to benefit from increased demand for Canadian gas.

Management Responsibility for Financial Reporting

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada and include certain estimated amounts which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised solely of directors who are not employees of the Company or of its subsidiaries. The Audit Committee meets regularly with management, the internal auditors and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

Ernst & Young LLP, Chartered Accountants, the shareholders' auditors, have full and free access to the Audit Committee, as does the Director of Internal Audit Services. The Audit Committee reports its findings to the Board of Directors.

Ernst & Young LLP has performed an independent audit of the consolidated financial statements in this report. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report.

February 15, 2001

M.E.J. Phelps
Chairman and Chief Executive Officer

G.M. Wilson
Executive Vice President and Chief Financial Officer

Auditors' Report

To the Shareholders of Westcoast Energy Inc.

We have audited the consolidated balance sheets of Westcoast Energy Inc. as at December 31, 2000 and 1999 and the consolidated statements of operations, retained earnings and cash flow for each of the years in the three year period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and its cash flow for each of the years in the three year period ended December 31, 2000 in accordance with accounting principles generally accepted in Canada.

Ernst & Young LLP

Chartered Accountants
Vancouver, Canada
February 15, 2001

Consolidated Statements of Operations

For the years ended December 31

$million, except for share data	2000	1999	1998
OPERATING REVENUES	8,955	6,265	7,376
OPERATING EXPENSES			
Cost of sales	6,755	4,258	5,473
Operation and maintenance	801	826	731
Depreciation	426	401	364
Taxes – other than income taxes	158	157	158
	8,140	5,642	6,726
OPERATING INCOME	815	623	650
OTHER INCOME			
Equity earnings	44	22	4
Foreign exchange gain (loss)	10	1	(3)
Allowance for funds used during construction	7	34	19
Investment and other income	107	149	79
	983	829	749
OTHER EXPENSES			
Interest (Note 2)	516	499	488
Other	11	7	9
	527	506	497
INCOME BEFORE UNDERNOTED ITEMS	456	323	252
INCOME TAXES (Note 4)			
Current	104	79	125
Deferred	(46)	(33)	(77)
	58	46	48
	398	277	204
NON-CONTROLLING INTEREST	10	10	6
NET INCOME	388	267	198
PROVISION FOR DIVIDENDS ON PREFERRED SHARES	48	45	37
NET INCOME APPLICABLE TO COMMON SHARES	340	222	161
COMMON SHARES – WEIGHTED AVERAGE (million)	117	114	105
EARNINGS PER COMMON SHARE – BASIC (Note 3)	$2.92	$1.95	$1.53
DIVIDENDS PER COMMON SHARE	$1.28	$1.28	$1.26

See accompanying notes

Consolidated Statements of Cash Flow

For the years ended December 31

$million, except for share data	2000	1999	1998
OPERATING ACTIVITIES			
Net income	388	267	198
Add (deduct) items to reconcile to net cash			
Non-controlling interest	10	10	6
Deferred income taxes	(46)	(33)	(77)
Depreciation and amortization	431	396	370
Net assets from price risk management activities	(67)	(13)	—
Equity earnings	(44)	(22)	(4)
Other	(31)	(106)	(45)
Operating cash flow	641	499	448
Non-cash working capital changes (Note 5)	(68)	(43)	54
	573	456	502
INVESTING ACTIVITIES			
Additions to fixed assets	(747)	(1,305)	(911)
Acquisitions (Note 8)	(66)	(39)	(137)
Dispositions (Note 9)	501	255	88
Investments and other	(471)	(48)	(85)
Net cash used by investing activities	(783)	(1,137)	(1,045)
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness	55	102	(80)
Long term debt additions	663	809	916
Long term debt repayments	(404)	(240)	(586)
Preferred shares issued (Note 6)	—	272	145
Preferred shares redeemed (Note 6)	—	(126)	(4)
Common shares issued (Note 7)	184	59	274
Non-controlling interest preferred shares issued	—	—	100
Dividends paid	(197)	(191)	(170)
Dividends paid to non-controlling interest	(8)	(10)	(5)
Net cash provided by financing activities	293	675	590
INCREASE (DECREASE) IN CASH AND SHORT TERM INVESTMENTS DURING THE YEAR	83	(6)	47
CASH AND SHORT TERM INVESTMENTS, BEGINNING OF YEAR	101	107	60
CASH AND SHORT TERM INVESTMENTS, END OF YEAR	184	101	107
OPERATING CASH FLOW PER COMMON SHARE (Note 3)	$5.50	$4.38	$4.24

See accompanying notes

Consolidated Balance Sheets

December 31

$million	2000	1999
ASSETS		
CURRENT ASSETS		
Cash and short term investments	184	101
Accounts receivable		
Trade	1,330	890
Other	103	111
Deferred income taxes (Note 4)	15	—
Assets from price risk management activities (Note 12)	1,340	111
Inventory	554	435
Prepayments	20	29
	3,546	1,677
INVESTMENTS (Note 13)	970	454
DEFERRED INCOME TAXES (Note 4)	306	—
ASSETS FROM PRICE RISK MANAGEMENT ACTIVITIES (Note 12)	561	186
FIXED ASSETS (Notes 2 and 14)		
Plant, property and equipment	12,589	12,096
Less accumulated depreciation	3,222	2,988
	9,367	9,108
DEFERRED CHARGES AND OTHER ASSETS (Note 16)	377	352
	15,127	11,777

On behalf of the Board:

Director

Director

$million	2000	1999
LIABILITIES		
CURRENT LIABILITIES		
Bank indebtedness (Note 15)	834	779
Accounts payable and accrued liabilities		
Trade	1,233	737
Other	180	225
Income and other taxes payable	66	36
Deferred income taxes (Note 4)	35	—
Liabilities from price risk management activities (Note 12)	1,223	100
Interest on debt	89	94
Long term debt due within one year (Note 2)	209	322
	3,869	2,293
LIABILITIES FROM PRICE RISK MANAGEMENT ACTIVITIES (Note 12)	612	175
LONG TERM DEBT (Note 2)	5,971	5,550
DEFERRED INCOME TAXES (Note 4)	880	333
NON-CONTROLLING INTEREST		
Preferred	130	130
Common	36	36
	166	166
PREFERRED SHAREHOLDERS' EQUITY		
PREFERRED STOCK (Note 6)	865	865
COMMON SHAREHOLDERS' EQUITY		
COMMON STOCK (Note 7)	1,944	1,755
CUMULATIVE TRANSLATION ADJUSTMENT (Note 17)	17	(1)
RETAINED EARNINGS	803	641
	2,764	2,395
	15,127	11,777

COMMITMENTS AND CONTINGENCIES (Notes 2,12,18 and 20)

See accompanying notes

Consolidated Statements of Retained Earnings

For the years ended December 31

$million	2000	1999	1998
RETAINED EARNINGS, BEGINNING OF YEAR	641	643	623
NET INCOME	388	267	198
Share issue costs (Notes 6 and 7)	(3)	(4)	(8)
Change in accounting for income taxes (Note 1)	(25)	—	—
Adoption of mark-to-market accounting (Note 1)	—	(36)	—
Transfer of retail services business (Note 10)	—	(38)	—
	1,001	832	813
DIVIDENDS			
Common shares	150	146	133
Preferred shares	48	45	37
	198	191	170
RETAINED EARNINGS, END OF YEAR	803	641	643

See accompanying notes

1. ACCOUNTING POLICIES

Accounting Principles

The Company is incorporated under the laws of Canada and prepares its financial statements in accordance with accounting principles generally accepted in Canada which, as applied in these financial statements except as described in Note 22, conform in all material respects with accounting principles generally accepted in the United States. The consolidated financial statements are presented in Canadian dollars.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities.

Consolidation

The consolidated financial statements include the accounts of the Company, its subsidiaries and its proportionate share of joint venture investments.

Major Subsidiaries (a)(wholly owned unless otherwise indicated)

Westcoast Gas Holdings Inc.
Westcoast Gas Inc.
UEI Holdings Inc.
Westcoast Gas Services Inc.
Centra Gas Holdings Inc.
Centra Gas Utilities Inc.
Union Gas Limited
Centra Gas British Columbia Inc.
Pacific Northern Gas Ltd. – 41% owned, including 100% of the voting shares
Engage Energy (Note 8)
Westcoast Power Holdings Inc.
Westcoast Power Inc.
Westcoast Energy International Inc.
Westcoast Capital Corporation
Westcoast Energy Risk Inc.
Enlogix Inc.

Major Joint Ventures

Foothills Pipe Lines Ltd. – 50% owned
Empire State Pipeline – 50% owned
Maritimes & Northeast Pipeline Limited Partnership – 37.5% owned
Maritimes & Northeast Pipeline, L.L.C. – 37.5% owned
McMahon Cogeneration Plant – 50% owned
Lake Superior Power Limited Partnership – 50% owned
Whitby Cogeneration Limited Partnership – 50% owned
P.T. Puncakjaya Power – 43% owned
Cantarell Nitrogen Facilities – 20% owned
Campeche Natural Gas Compression Services Project – 45% owned (Note 20)

(a) In 1999 and 1998, respectively, the Company sold its wholly owned subsidiaries Centra Gas Manitoba Inc. and Centra Gas Alberta Inc. (Note 9)

For interests acquired or disposed of during the year, purchase accounting is applied on a prospective basis from the date of the transaction.

Revenue Recognition

The Company recognizes revenue when the service has been performed or delivered or when it is available for delivery under take-or-pay contracts. Revenue from the sale of goods is recognized when the products have been delivered.

Gas sales are recorded on the basis of meter readings plus an estimate of customer usage since the last meter reading date prior to the end of the year.

Revenues derived from selling power and steam are recognized as service is provided at the rates defined in the individual power sale agreements.

For the Company's energy marketing operations, revenues arising from the sale of physical natural gas and electric power are recognized in the period of delivery. See Price Risk Management for the revenue recognition policy on risk management activities for energy marketing operations.

Rental income from assets under operating leases is recognized over the term of the lease on a straight-line basis. Interest income related to finance receivables is recognized on an accrual basis to provide a constant effective yield on the net investment in the receivables.

Price Risk Management

Certain of the Company's operations engage in price risk management activities to manage exposure to changes in the market prices of natural gas, electric power, interest rates, foreign currency exchange rates and transportation contracts.

The cash flow impact of financial instruments is reflected as cash flows from operating activities in the Consolidated Statements of Cash Flow.

Energy Marketing

Effective January 1, 1999, the Company adopted mark-to-market accounting for the Company's energy marketing operations. This accounting policy change has been applied on a cumulative retroactive basis without restatement of individual prior years. The impact of the accounting change on retained earnings as at January 1, 1999 is as follows:

($million)	**1999**
Assets from price risk management activities	
Current	198
Long term	141
Liabilities from price risk management activities	
Current	(188)
Long term	(141)
Unamortized energy contracts	(58)
Other unamortized energy contracts	(3)
Deferred income taxes	15
Retained earnings	(36)

Under the mark-to-market method of accounting, all physical and financial marketing transactions are recorded at market value, net of any premiums/discounts or future physical delivery related costs, and are shown as Assets and Liabilities From Price Risk Management Activities on the Consolidated Balance Sheets. Unrealized gains and losses from newly originated contracts, contract restructurings and the impact of price movements are recorded in Operating Revenues in the Consolidated Statements of Operations. Changes in the assets and liabilities from price risk management activities result primarily from changes in the valuation of the portfolio of contracts, maturity and settlement of contracts and newly originated transactions. The market prices used to value these transactions reflect management's best estimate considering various factors including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments. The values are adjusted to reflect the potential impact and associated costs of liquidating the Company's position in an orderly manner over a reasonable period of time under present market conditions.

Non-trading activities

Derivative and other financial instruments are also utilized in connection with non-trading activities. The Company enters into forward, future, swap and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Foreign Currency

The Company's foreign businesses maintain their accounts in United States dollars or local currency. These businesses are operationally and functionally self-sustaining and accordingly, the assets and liabilities are translated into Canadian dollars at the year-end exchange rate, and revenues and expenses are translated into Canadian dollars at the average exchange rate for the year. The resulting unrealized cumulative translation gains or losses are deferred as a separate component of common shareholders' equity.

For development expenditures applicable to foreign businesses, costs are translated into Canadian dollars at the prevailing exchange rate as incurred.

Funds on deposit with banks and current liabilities payable in United States dollars have been translated into Canadian dollars at the year-end exchange rate. Any resulting gain or loss is reflected in income.

The Company enters into foreign currency swaps to manage certain foreign currency risks.

Cash and Short Term Investments

Short term investments, consisting of money market instruments with original maturities of three months or less, are considered to be cash equivalents and are recorded at cost, which approximates current market value.

Income Taxes

Effective January 1, 2000, the Company adopted the new recommendations of The Canadian Institute of Chartered Accountants (CICA) with respect to accounting for income taxes. This accounting policy change has been applied on a cumulative retroactive basis without restatement of individual prior years. The effect of adopting the liability method of tax allocation on retained earnings as at January 1, 2000 is as follows:

($million)	2000
Deferred income tax assets	
Current	14
Long term	253
Deferred income tax liabilities	
Current	(4)
Long term	(594)
Fixed assets	292
Deferred charges	14
Retained earnings	(25)

For the year ended December 31, 2000, application of the recommendations decreased pre-tax income by $18 million because of increased depreciation expense resulting from the requirement to report assets acquired in prior business combinations at their pre-tax amounts.

Under the new recommendations, the liability method of tax allocation is used in accounting for income taxes for non-regulated businesses. Under this method, deferred income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. Prior to the adoption of the new recommendations, income tax expense was determined using the deferral method of tax allocation. Deferred tax expense was based on items of income and expense that were reported in different years in the financial statements and tax returns and measured at the tax rate in effect in the year the difference originated.

Rate-regulated businesses of the Company continue to use the income taxes currently payable method as directed by the regulators and as permitted under the new recommendations. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items.

Inventory

Materials and supplies are valued at the lower of average cost or net realizable value. Natural gas inventories are valued at costs approved by the regulators.

Investments

Investments in which the Company exercises significant influence, but not control or joint control, are accounted for by the equity method. Other investments are carried at cost, net of write downs for declines in value that are other than temporary in nature. Finance contracts represent customer financing for the purchase of natural gas appliances which are due over periods of up to 10 years.

Leases

Certain equipment is leased on terms which transfer substantially all of the benefits and risks of ownership to customers, and accounted for as direct financing leases. Finance income is recognized over the term of the lease in a manner that produces a constant rate of return on the lease investment.

Assets under operating leases are recorded at cost. Depreciation is computed on a straight-line basis over the estimated useful lives of the related assets.

Fixed Assets

Plant, property and equipment are recorded at cost. In accordance with normal utility practice, the cost of utility plant, property and equipment includes an allowance for funds used during construction. For non-regulated businesses, interest costs incurred during construction are capitalized as part of the cost of the asset.

Assets employed in utility businesses are depreciated on the straight-line basis at rates approved by regulatory authorities. Power generation facilities are depreciated on a unit of production basis. Other non-utility assets are depreciated on the straight-line basis. The rates used resulted in a composite rate of 3.5% for the year ended December 31, 2000 (for the year ended December 31, 1999 – 3.4%, for the year ended December 31, 1998 – 3.3%).

For some of the Gas Distribution businesses, the regulators have authorized the recovery over time of anticipated future removal and site restoration costs. For the other utility businesses, the regulators have not yet directed that future removal and site restoration costs be accrued. Upon retirement or sale of items of utility plant, property or equipment, the original costs associated with such items are charged against the applicable accumulated depreciation accounts and the cost of removal net of proceeds of disposal are charged to accumulated depreciation.

The cost of fixed assets is reduced by contributions and grants in aid of construction received from customers and from governmental bodies in support of specific pipeline and distribution facilities.

Capitalization and Maintenance

Maintenance and repairs are charged to expense accounts when incurred. The costs of major replacements, extensions or improvements are capitalized as plant, property and equipment. For power generation facilities, provisions for major maintenance and gas turbine overhauls are accrued annually.

Deferred Charges

Costs as required or permitted by the regulators have been deferred to be recovered from future revenues. Certain regulatory deferrals are subject to future decisions by the relevant regulators who will determine the treatment to be given the various items.

Costs incurred for development projects which benefit future periods are deferred and upon commencement of operations are amortized on a straight-line basis over the expected period of benefit, or expensed upon abandonment of the project.

Costs related to long term debt are deferred and amortized on a straight-line basis over the term of the respective debt issues.

Goodwill

Goodwill represents the excess cost of an investment over the fair value of the net assets acquired and is amortized on a straight-line basis over a maximum period of 20 years. Goodwill will be written down to net recoverable value if declines in value, considered to be other than temporary, occur based upon expected undiscounted cash flows.

Employee Benefit Plans

Effective January 1, 2000, the Company adopted, on a prospective basis, the new recommendations of the CICA with respect to accounting for employee future benefits. The new recommendations modify the previous CICA requirements for pension costs and obligations and apply the modified requirements to non-pension benefits. Under the new recommendations, the Company will replace pay-as-you-go method of accounting for post-retirement benefits other than pensions with accrual accounting that recognizes the liability and expense for the period when the benefits are earned, not received. The new recommendations for accounting for employee future benefits do not impact certain rate-regulated businesses of the Company, which continue with pay-as-you-go accounting as directed by the regulators. The effect of adopting the new recommendations was to decrease 2000 pre-tax income by approximately $14 million.

Under the new recommendations, the Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plans is 17 years. The average remaining service period of the active employees covered by the other retirement benefits plans is 17 years.

For defined contribution plans maintained by the Company, contributions payable by the Company are expensed as pension costs.

Regulation

Certain operations of the Company are engaged in utility businesses which are subject to regulation by federal, provincial or state agencies within Canada and the United States. The regulatory authorities exercise statutory authority over matters such as rate of return, natural gas exports, construction and operation of natural gas facilities, accounting practices and rates, tolls and charges. The regulatory rates of return on common equity applicable to utility businesses are:

For the years ended December 31 (percent)

	Equity Component of Rate Base			Return on Common Equity		
	2000	**1999**	**1998**	**2000**	**1999**	**1998**
Westcoast Energy Inc.						
– Pipeline	30	30	30	(a)	(a)	(a)
– Field Services	38.4	38.6	38.6	(a)	(a)	(a)
Foothills Pipe Lines Ltd.	30	30	30	9.90	9.58	10.21
Empire State Pipeline	40	40	40	12.50	12.50	12.50
Union Gas Limited (b)	35	35	34	9.61	9.61	10.53
Centra Gas British Columbia Inc.	35	35	35	8.42	7.76	8.59
Pacific Northern Gas Ltd.	36	36	36	10.25	10.00	10.75
Maritimes & Northeast Pipeline	25	25	25	13-14	13-14	13-14
Alliance Pipeline	30	30	30	10.9-11.2	10.9-11.2	10.9-11.2
Vector Pipeline (recourse rates)	30	30	—	14.00	14.00	—

(a) In 1998, the Company and its major customers agreed to a framework for light-handed regulation of the gathering and processing facilities which are regulated by the National Energy Board (NEB). The framework became effective immediately upon approval by the NEB in June 1998.

The framework defines the principles under which the Company negotiates service contracts individually with new and existing shippers, including tolls applicable to gathering and processing services. Consistent with these principles, the Company is responsible for the utilization of its gathering and processing assets.

Transmission services continue to operate under the multi-year incentive-based toll settlement (effective from 1997 to 2001) approved by the NEB in August 1997.

(b)The Company has filed an application with the Ontario Energy Board (OEB) for an order approving rates for the year 2000 and thereafter in accordance with a performance based regulation mechanism. The application also sought an order from the OEB approving the unbundling of certain rates charged for the sale, distribution, transportation and storage of natural gas. The hearing for this application concluded in August 2000, but a decision has not yet been rendered by the OEB. Revenue in 2000 includes an assumption for cost pass-through and other items based upon previous regulatory practice. The full impact of the decision, which is not certain, will be accounted for at the date of the regulatory decision.

Gain on Sale of Finance Assets

The Company periodically sells certain of its asset-backed finance contracts to securitization vehicles. Securitization transactions are accounted for as sales of finance contracts. These sales are non-recourse to the Company except to the extent of the Company's retained interest in these securitization vehicles. These transactions result in the removal of the finance contracts from the Company's Consolidated Balance Sheets, the recording of assets received and a gain on sale when the significant risks and rewards of ownership are transferred to the purchaser. The assets received are generally cash and a retained interest in the cash flow of the finance contracts sold. Such retained interest is recorded at estimated fair value and may include cash collateral accounts, excess spread assets, and securities backed by the finance contracts sold. Proceeds on sale are computed as the aggregate of the initial cash consideration and the present value of any additional sale proceeds, net of a provision for anticipated credit losses on the securitized finance contracts and the amount of an arm's length servicing fee.

Any gains resulting from securitization transactions are deferred and amortized over the expected life of the securitized portfolio.

Income is earned on the securitization investments on an accrual basis. The carrying value of this asset is reduced, as required, based on changes in the Company's share of the estimated credit losses and the effects of changes in the payment rate on the securitized finance contracts. The Company continues to manage the securitized finance contracts and recognizes income equal to an arm's length servicing fee over the term of the securitized finance contracts.

Stock-Based Compensation Plan

The Company has one stock-based compensation plan, which is described in Note 11. No compensation expense is recognized for this plan when the stock options are issued to employees. Any consideration paid by employees on exercise of stock options is credited to share capital. Share appreciation rights exercised are charged to retained earnings.

Comparative Figures

Certain comparative figures have been reclassified to conform to the 2000 presentation.

2. LONG TERM DEBT

December 31 ($million)	Due Date	2000	1999
WESTCOAST ENERGY INC.			
Unsecured Debentures			
8.2% – average fixed rate (8.3% – 1999)	2001 – 2027	2,110	2,155
CENTRA GAS UTILITIES INC. AND SUBSIDIARIES			
Unsecured Senior Debentures			
9.1% – average fixed rate (9.5% – 1999)	2001 – 2025	1,705	1,642
Term Bank Loans and Other			
8.1% – average fixed rate (7.9% – 1999)	2001 – 2009	239	245
CENTRA GAS HOLDINGS INC.			
Term Bank Loans			
6.0% – average year end rate (5.5% – 1999)	2003	348	350
FOOTHILLS PIPE LINES LTD.			
Term Bank Loans			
7.4% – average year end rate (6.7% – 1999)	2003 – 2005	165	163
PACIFIC NORTHERN GAS LTD.			
Secured Debentures			
9.1% – average fixed rate (9.3% – 1999)	2002 – 2027	86	89
MARITIMES & NORTHEAST PIPELINE			
Senior Secured Notes			
US$90 million			
7.7% – average year end rate (7.7% – 1999)	2019	135	130
Senior Secured Bonds			
6.9% – average fixed rate (6.9% – 1999)	2019	98	98
Term Bank Loans			
5.9% – average year end rate (5.9% – 1999)	2009	168	117
US$99 million			
7.6% – average fixed rate (6.4% – 1999)	2009	145	142
CANTARELL NITROGEN FACILITIES			
Term Bank Loans			
US$125 million			
7.4% – average year end rate (6.3% – 1999)	2008 – 2010	187	180
EMPIRE STATE PIPELINE			
Term Bank Loans			
US$38 million ($43 million – 1999)			
7.1% – average year end rate (5.9% – 1999)	2009	57	62
WESTCOAST POWER HOLDINGS INC. AND SUBSIDIARIES			
Senior Secured Notes			
9.3% – average fixed rate (9.3% – 1999)	2006	18	22
Term Bank Loans and Other			
7.3% – average year end rate (7.2% – 1999)	2004 – 2021	496	477
WEI HOLDINGS (U.S.) INC.			
Term Bank Loans			
US$149 million			
7.3% – average year end rate	2003	223	—
		6,180	5,872
Deduct long term debt due within one year		209	322
		5,971	5,550

Consolidated long term debt repayments, including sinking fund obligations, are:

Due Date	$million	Due Date	$million
2001	209	2006 – 2010	1,683
2002	362	2011 – 2015	787
2003	1,028	2016 – 2020	790
2004	416	2021 – 2025	318
2005	302	2026 – 2030	285
	2,317		3,863

Consolidated interest on long term debt for the year ended December 31, 2000 was $467 million (for the year ended December 31, 1999 – $460 million, for the year ended December 31, 1998 – $441 million).

Each of the Term Bank Loans and Other facilities held by various Company subsidiaries and joint ventures are secured and are generally non-recourse to the Company. Security is typically a pledge of the borrowing entity's assets, key agreements, or ownership interests, or a combination thereof. However, the Company has provided guarantees and has arranged letters of credit which support the Maritimes & Northeast Pipeline, Cantarell Nitrogen Project and Fort Frances Cogeneration Plant totalling $867 million. Guarantees, with a value of $827 million, will be released after completion and satisfactory testing of the project facilities to which they relate.

3. EARNINGS AND OPERATING CASH FLOW PER COMMON SHARE

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year.

For the years ended December 31	2000	1999	1998
Net income applicable to common shares ($million)	340	222	161
Number of shares (million)			
Shares outstanding, beginning of year	115	113	103
Changes due to common shares issued, options exercised and shares issued under the Dividend Reinvestment and Share Purchase Plan	2	1	2
Weighted average shares for the year	117	114	105
Earnings per common share – basic	$2.92	$1.95	$1.53

Fully diluted earnings per common share are calculated using an adjusted average number of common shares outstanding during the year and an adjusted net income applicable to common shares, which reflect the potential exercise of share purchase options and the conversion of preferred shares (Notes 6 and 7). An imputed after-tax return of 2.8% has been used in these calculations.

For the year ended December 31	2000
Adjusted net income applicable to common shares ($million)	375
Adjusted weighted average shares for the year (million)	139
Earnings per common share – fully diluted	$2.70

Operating cash flow per common share is also calculated using the weighted average number of common shares outstanding during the year applied to cash flow from operating activities before adjusting for non-cash working capital changes.

For the years ended December 31	2000	1999	1998
Operating cash flow before non-cash working capital changes ($million)	641	499	448
Weighted average shares for the year (million)	117	114	105
Operating cash flow per common share	$5.50	$4.38	$4.24

4. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

December 31 ($million)	2000
Deferred tax liabilities	
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	765
Loss carryforwards	(51)
Other – net	201
Total deferred tax liabilities	915
Deferred tax assets	
Depreciation and amortization in excess of capital cost allowance claimed for income tax purposes	219
Loss carryforwards	80
Other – net	22
Total deferred tax assets	321
Net deferred tax liabilities	594

For financial reporting purposes, income before income taxes and non-controlling interest includes the following components:

For the years ended December 31 ($million)	2000	1999	1998
Income before income taxes and non-controlling interest			
Canada	354	273	249
Foreign	102	50	3
	456	323	252
Current income taxes			
Canada	103	83	121
Foreign	1	(4)	4
	104	79	125
Deferred income taxes			
Canada	(91)	(47)	(67)
Foreign	45	14	(10)
	(46)	(33)	(77)
Provision for income taxes	58	46	48

Significant components of the provision for income taxes attributable to continuing operations are as follows:

For the years ended December 31 ($million)	Liability Method	Deferred Method	
	2000	1999	1998
Current tax expense	104	79	125
Deferred income tax expense relating to origination and reversal of temporary differences	31	(35)	(45)
Deferred income tax benefit resulting from recognition of loss carryforwards	1	13	(11)
Deferred income tax expense resulting from rate change	(53)	—	—
Net regulated deferrals included for tax purposes	(5)	(2)	(21)
Regulatory drawdown of deferred income taxes	(20)	(9)	—
Income tax expense	58	46	48

At December 31, 2000, the Company has loss carryforwards of $379 million for income tax purposes that expire as follows: 2002 – $35 million; 2003 – $12 million; 2004 – $3 million, and thereafter – $329 million. For financial reporting purposes a deferred tax asset of $131 million has been recognized in respect of these loss carryforwards.

The reconciliation of income tax attributable to continuing operations computed at the statutory tax rates to income tax expense is:

For the years ended December 31 ($million)	Liability Method	Deferred Method	
	2000	1999	1998
Combined Canadian federal and provincial statutory income tax rates, including surtaxes (percent)	44.8	45.0	45.0
Statutory income tax rates applied to accounting income	204	145	113
Increase (decrease) in income taxes resulting from:			
– The use of the income taxes currently payable method applicable to utility operations:			
– Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	(55)	(22)	(37)
– Other items recognized for income tax purposes subsequent to (in advance of) accounting income recognition	10	(27)	(18)
	(45)	(49)	(55)
– Foreign earnings subject to different tax rates	(20)	(10)	(4)
– Utilization of prior years' losses which have not been previously recognized	(5)	(25)	(17)
– Resource allowance deduction	(11)	(10)	(11)
– Equity earnings	(19)	(2)	—
– Deferred income tax rate adjustments	(53)	—	—
– Large corporation tax in excess of surtax	17	19	17
– Regulatory drawdown of deferred income taxes	(20)	(9)	—
– Other – net	10	(13)	5
	(146)	(99)	(65)
Provision for income taxes	58	46	48
Effective rate of income taxes (percent)	12.7	14.2	19.0

Certain of the Company's utility businesses have been directed by their respective regulators to refund deferred taxes collected in prior years by applying them against future costs in order to reduce tolls. The deferred taxes will be reduced in future years as the timing differences which gave rise to these deferred income taxes reverse, or as amounts are applied to reduce tolls.

If all the companies had used the liability method for fiscal 2000, or the income tax allocation method for fiscal 1999 and 1998, for regulated utility operations, the additional deferred income tax liabilities and assets and additional deferred income tax expense would be:

For the years ended December 31 ($million)	Liability Method	Deferred Method	
	2000	1999	1998
Deferred tax liability – long term, beginning of year	689	704	655
Deferred income tax (recovery) expense	(30)	16	49
Adjustment on transfer of retail services business (Note 10)	—	(31)	—
Deferred tax liability – long term, end of year	659	689	704

5. SUPPLEMENTAL CASH FLOW INFORMATION

Non-cash working capital changes

For the years ended December 31 ($million)	2000	1999	1998
Accounts receivable	(808)	44	84
Inventory and prepayments	(106)	(67)	(8)
Accounts payable and accrued liabilities	809	27	(42)
Interest and taxes payable	23	17	(53)
	(82)	21	(19)
Attributable to financing and investing activities	(14)	64	(73)
Attributable to operating activities	(68)	(43)	54

Interest and tax payments

For the years ended December 31 ($million)	2000	1999	1998
Interest	556	514	514
Income taxes	84	43	133

6. PREFERRED STOCK

The Company is authorized to issue an unlimited number of preferred shares, in two classes issuable in series, without nominal or par value. Preferred shares issued for cash and outstanding are:

December 31 ($million)	2000	1999
4,597,187 (1999 – 4,610,237) – 8.08% Cumulative First Preferred Shares, Series 2 (a)(f)	115	115
8,000,000 – 4.90% Cumulative Redeemable First Preferred Shares, Series 5 (c)(f)	200	200
5,000,000 – 4.72% Cumulative Redeemable First Preferred Shares, Series 6 (c)(f)	125	125
6,000,000 – 5.50% Cumulative First Preferred Shares, Series 7 (d)(f)	150	150
6,000,000 – 5.60% Cumulative First Preferred Shares, Series 8 (e)(f)	150	150
5,000,000 – 5.00% Cumulative Redeemable First Preferred Shares, Series 9 (c)(f)	125	125
	865	865

(a) The Series 2 Preferred Shares are convertible into common shares of the Company at the option of the holder or the Company at the ratio determined by dividing $25.00 by the greater of $1.00 and 95% of a 20 day weighted average trading price of the Company's common shares. In 2000, preferred shareholders exercised their conversion privileges, resulting in the issuance of 13,514 (1999 – 18,660) common shares of the Company (Note 7).

(b) The 6.90% Cumulative Redeemable First Preferred Shares, Series 4, were redeemed by the Company in October 1999 for cash of $125 million plus accrued dividends.

(c) The Series 5, 6 and 9 Preferred Shares are convertible into common shares of the Company, at the option of the holder, on or after January 1, 2002, April 15, 2003 and January 15, 2005, respectively, at the ratio determined by dividing $25.00 together with accrued and unpaid dividends, by the greater of $3.00 and 95% of a 20 day weighted average trading price of the Company's common shares.

The Company has the option to redeem the Series 5, 6 and 9 Preferred Shares on or after October 1, 2001, January 15, 2003 and October 15, 2004, respectively, at $25.00 plus accrued and unpaid dividends or to convert these shares into common shares of the Company, at the ratio determined by dividing $25.00 together with accrued and unpaid dividends, by the greater of $3.00 or 95% of a 20 day weighted average trading price of the Company's common shares.

(d) The Company has the option to redeem the Series 7 Preferred Shares on or after October 15, 2013 at $25.00 per share plus accrued and unpaid dividends.

(e) The Company has the option to redeem the Series 8 Preferred Shares on or after July 15, 2004 at prices ranging from $25.00 to $26.00 per share plus accrued and unpaid dividends.

(f) The issue costs of preferred shares, net of income taxes, have been charged to retained earnings.

7. COMMON STOCK

The Company is authorized to issue an unlimited number of common shares without nominal or par value. Common shares issued and outstanding are:

	shares	$million
Balance – December 31, 1997	103,245,876	1,412
(a) Shares issued for cash under a public offering at a price of $30.30 per share. The issue costs of these shares, amounting to $9 million, less income taxes of $4 million, have been charged to retained earnings.	7,315,000	222
(b) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from $26.85 to $33.65 per share.	1,701,448	51
(c) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from $17.69 to $24.02 per share.	270,109	6
(d) Shares issued on the conversion of First Preferred Shares, Series 2	138,334	4
Balance – December 31, 1998	112,670,767	1,695
(a) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from $25.98 to $30.51 per share.	1,989,110	55
(b) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from $17.69 to $24.02 per share.	168,978	4
(c) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 6)	18,660	1
Balance – December 31, 1999	114,847,515	1,755
(a) Shares issued for cash under a public offering at a price of $32.25 per share. The issue costs of these shares, amounting to $5 million, less income taxes of $2 million, have been charged to retained earnings.	4,000,000	129
(b) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from $21.93 to $27.84 per share.	2,121,003	50
(c) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from $17.69 to $34.45 per share.	461,334	10
(d) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 6)	13,514	—
Balance – December 31, 2000	121,443,366	1,944

In 2000, the Directors granted 951,600 options, at prices ranging from $24.54 to $32.40 per share based on a 10 day weighted average trading price of the Company's common shares on The Toronto Stock Exchange. At December 31, 2000, 4,873,719 common shares were under option at prices ranging from $17.69 to $34.45 per share, of which 3,116,720 are eligible for share appreciation rights that allow the holder to receive 50% of the appreciated value in cash and the balance in common shares of the Company. At December 31, 2000, 2,784,688 common shares were reserved for issuance upon the exercise of options.

At December 31, 2000, 6,989,067 common shares were reserved for issuance under the Dividend Reinvestment and Share Purchase Plan.

Preferred shares amounting to $20 million held by a non-controlling interest in UEI Holdings Inc. are convertible into common shares of the Company at any time at the option of the holder at 95% of a 20 day weighted average trading price of the Company's common shares on The Toronto Stock Exchange.

8. ACQUISITIONS (Note 24)

Engage Energy

During 2000, the Company and The Coastal Corporation (Coastal) terminated their Engage Energy joint venture. The termination of the joint venture agreement resulted in the Company purchasing the additional 50% interest in Engage Energy Canada L.P. (Engage Canada), increasing its interest to 100%. The costs of acquiring the Company's interest in Engage Canada exceed the equivalent proportion of the acquired net assets by $16 million. This excess has been allocated to assets from price risk management activities and goodwill. The acquisition has been accounted for by the purchase method as follows:

December 31 ($million)	2000
Fixed assets	6
Working capital	29
Assets from price risk management activities	
Current	213
Long term	107
Goodwill	10
Liabilities from price risk management activities	
Current	(204)
Long term	(94)
Deferred income taxes	(10)
Cash purchase price	57

In conjunction with the termination of the joint venture agreement, the Company purchased for cash approximately $9 million of contracts from Engage Energy US, L.P. and subsequently sold its 50% interest in Engage Energy US, L.P. to Coastal for cash of $81 million.

Vector Pipeline

During 1999, the Company purchased a 30% equity interest in the Vector Pipeline (Vector) from an existing Vector partner for cash of $30 million. The costs of acquiring the Company's interest in Vector exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Vector by $6 million. This excess is being amortized on a straight-line basis over 15 years beginning December 1, 2000, the commencement date of operations.

Heating, Ventilation and Air Conditioning (HVAC) Businesses

During 1999 and 1998, the Company purchased 100% of the outstanding shares in, or certain assets of, 13 and 15 HVAC businesses, respectively. The acquisitions have been accounted for by the purchase method as follows:

December 31 ($million)	1999	1998
Fixed assets	2	4
Working capital	3	3
Goodwill	5	17
Assumption of long term debt	(1)	(1)
Cash purchase price	9	23

Alliance Pipeline and Aux Sable Liquids Facility

During 1998, the Company purchased additional interests in the Alliance Pipeline (Alliance) and Aux Sable Liquids Facility (Aux Sable) from existing Alliance partners for cash of $88 million. As a result of these transactions, the Company's equity interest in Alliance and Aux Sable increased to 23.6% from 10.5%. The costs of acquiring the Company's interests in Alliance exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Alliance by $20 million. This excess is being amortized on a straight-line basis over 25 years beginning December 1, 2000, the commencement date of operations.

Island Cogeneration Project (ICP)

During 1998, the Company purchased an additional 60% (to a cumulative interest of 100%) in the ICP from its partner for cash of $26 million. The costs of acquiring the Company's interest in ICP exceed the figure at which the equivalent proportion of the net assets is recorded in the books of ICP by $21 million. This excess has been allocated to fixed assets and energy contracts.

9. DISPOSITIONS (Notes 8 and 24)

(a) In 2000, the Company sold 51% of its interest in its wholly owned subsidiary NGX Canada Inc. for cash of $8 million, resulting in a pre-tax gain of $5 million.

(b) In 2000, the Company sold its 74% interest in the EastCoast Power Project in Australia for cash of $17 million, resulting in a pre-tax gain of $12 million.

(c) In 2000, Westcoast Capital Corporation sold certain of its rental assets as a direct financing lease for proceeds of $344 million. The proceeds approximated net book value.

(d) In 2000, the Company sold 25% of its interest in the wholly owned Bayside Power Project for cash of $32 million. The proceeds approximated net book value.

(e) In 2000, the Company sold its 50% interest in the Liberty Electric Power Project for cash of $13 million, resulting in a pre-tax gain of $3 million.

(f) In 2000, the Company sold 40% of its interest in the wholly owned Frederickson Power Project for cash of $4 million. The proceeds approximated net book value.

(g) In 2000, the Company sold its 33% interest in NrG Information Services Inc. for cash of $2 million. The proceeds approximated net book value.

(h) In 1999, the Company sold its wholly owned subsidiary Centra Gas Manitoba Inc. for cash of $245 million, resulting in a pre-tax gain of $76 million.

(i) In 1999, the Company sold its interest in the Fort Nelson Powerline joint venture for cash of $10 million, resulting in a pre-tax gain of $5 million.

(j) In 1998, the Company sold its wholly owned subsidiary Centra Gas Alberta Inc. for cash of $61 million, resulting in a pre-tax gain of $20 million.

(k) In 1998, the Company sold its 50% interest in a joint venture to build a natural gas pipeline in Australia for cash of $27 million, resulting in a pre-tax gain of $8 million.

Supplemental cash flow information regarding dispositions is as follows:

December 31 ($million)	2000	1999
Cash and short term investments	31	—
Total assets other than cash and short term investments	1,209	517
Total liabilities	745	272

10. TRANSFER OF RETAIL SERVICES BUSINESS

On January 1, 1999, following the approval of the OEB, Union Gas Limited transferred its net assets relating to the retail services business to UEI Holdings Inc. This related party transaction has been accounted for at the carrying amounts and resulted in a charge to retained earnings of $38 million as at January 1, 1999, consisting of the costs of transfer of $7 million and the recording of previously unrecorded deferred income taxes on assets transferred of $31 million. The unrecorded deferred income taxes arose through the use, prior to the transfer, of the income taxes currently payable method by Union Gas Limited for the retail services business pursuant to regulatory direction.

11. STOCK-BASED COMPENSATION PLAN

Stock Option Plan

Under the Long Term Incentive Share Option Plan 1989 (1989 Plan), the Company has granted regular, key employee retention, and performance-based stock options to its employees. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of the Company's shares on the date of grant.

Regular stock options vest in five equal stages with the first stage vesting immediately on the date of the grant and the remainder in four equal annual stages commencing on the first anniversary of the date of grant. Key employee retention stock options commence vesting two years after the date of issuance and then vest in three equal annual installments. The maximum term of both stock options awarded under the 1989 Plan is ten years. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

Performance-based stock options commence vesting when a pre-determined performance threshold has been achieved. The options then vest in three equal annual stages commencing on the date the performance threshold is achieved. The maximum term for performance-based options awarded under the 1989 Plan ranges from five to eight years. Share appreciation rights have not been attached to performance-based options awarded under the 1989 Plan.

A summary of the status of the Company's stock option plan as of December 31, 2000 and 1999, and changes during the years ending on those dates is presented below:

	2000		1999	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of year	4,690,853	$25.36	3,631,220	$25.00
Granted	951,600	$26.37	1,351,100	$25.70
Exercised	(461,335)	$21.29	(168,978)	$20.87
Forfeited	(307,399)	$27.27	(122,489)	$25.09
Outstanding at end of year	4,873,719	$25.82	4,690,853	$25.36
Options exercisable at year-end	2,042,160		1,865,740	

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/00	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/00	Weighted-Average Exercise Price
$17 – 22	1,404,500	3.1	$20.66	1,379,500	$20.66
$24 – 25	1,887,960	8.6	$24.65	349,740	$24.41
$28 – 31	664,900	8.9	$28.68	190,400	$28.68
$33 – 35	916,359	3.4	$34.07	122,520	$34.45
$17 – 35	4,873,719			2,042,160	

12. FINANCIAL INSTRUMENTS

Energy Marketing

Engage Energy engages in the marketing and trading of natural gas and electric power and executes financial derivatives related to these commodities for overall management of its contractual portfolio and physical positions. Engage Energy's portfolio of natural gas and electric power contracts is comprised primarily of contracts for purchase and delivery of natural gas and power and the following financial contracts: forward, netbacks, future, swap and option contracts for periods of up to 15 years, which also include related fixed and floating price commitments. These transactions give rise to certain business risks, including market and credit risk.

Market Risk

Market risk is the risk that the value of the portfolio will change, either favourably or unfavourably, in response to changing market conditions including but not limited to commodity price changes. Market risks are monitored by an internal Risk Management Committee independent of Engage Energy's trading activities to ensure compliance to Company standards. The Company monitors and manages its exposure to market risk through a variety of risk management techniques. Such procedures include measurement of risk, market comparisons, monitoring of all commitments and positions, and daily reporting to senior management. In addition, sensitivity to changes in market price and market volatility are examined on a daily basis.

Credit Risk

Credit risk is the risk of loss from non-performance by suppliers, customers or financial counterparties to a contract. In connection with the market valuation of its energy trading, leasing and finance contracts, the Company maintains certain reserves for a number of risks and costs associated with these future commitments. Among others, these include reserves for credit risks based on the financial condition and short and long term exposures to counterparties. The Company maintains credit policies which management believes significantly minimizes overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure, monitoring of concentration of exposure to any one individual or counterparty or industry, monitoring of aggregate exposure against limits by the internal credit risk management group and the use of standardized agreements which allow for the netting of positive and negative exposures associated with a single counterparty. The credit risk management group reviews and monitors the application of these policies for suppliers, customers and counterparties. Customers not meeting minimum credit standards must provide security. The Company's energy marketing operations are primarily concentrated in the natural gas and electric power industries and major customers' operations are also heavily concentrated in the same industries. The counterparties associated with assets from price risk management activities net of reserves as of December 31, 2000 and 1999 are summarized as follows:

December 31 ($million)	**2000**		**1999**	
	Investment Grade (a)	**Total**	**Investment Grade (a)**	**Total**
Gas and electric utilities	122	122	63	64
Energy marketers	497	519	39	41
Financial institutions	284	284	51	51
Independent power producers	2	6	41	41
Oil and gas producers	294	511	37	62
Industrials	7	9	3	8
Pipelines and other	142	259	30	30
Energy retailer	—	191	—	—
Total	1,348		264	
Assets from price risk management activities (b)		1,901		297

(a) "Investment Grade" is primarily determined using publicly available credit ratings along with consideration of collateral, which may encompass letters of credit, parent company guarantees and property interests. Included in "Investment Grade" are counterparties with a minimum Standard & Poor's or Dominion Bond Rating Service rating of BBB- or Moody's rating of Baa3, respectively, or minimum implied (through internal financial credit analysis) Standard & Poor's equivalent rating of BBB-.
(b) Six and two customers' exposures at December 31, 2000 and 1999, respectively, comprise greater than 5% of Assets From Price Management Activities. All are included above as Investment Grade.

Commodity Price Risk

The natural gas supply of the Company's Gas Distribution businesses includes gas supply contracts with pricing mechanisms that vary with gas price indices, rather than fixed prices. For some of these contracts, the effective purchase price has been fixed through the use of gas price swap contracts. The differences between the price of natural gas used for toll purposes and the effective cost of gas purchased is deferred for future disposition as approved by the respective regulators. The difference, if any, between amounts actually recorded as receivable or payable at year end and amounts actually approved for recovery by the regulator is charged to income at the time of the regulator's decision. The net payable position of these deferrals at December 31, 2000 was approximately $40 million (December 31, 1999 – $63 million).

Approximately 48% of the forecast 2001 gas supply of the Gas Distribution businesses from January through December 2001 is indexed to variable pricing mechanisms. At December 31, 2000 the purchase price applicable to 12 billion cubic feet (Bcf) or 16% of this indexed supply has been effectively fixed through the use of natural gas swaps and other contracts.

Notional Amounts of Derivative Instruments

The approximate notional amount of natural gas derivative instruments at December 31, 2000 is 2,424 Bcf (December 31, 1999 – 2,172 Bcf) with a maximum 8 and 10 years, respectively, in term.

Notional amounts reflect the volume of transactions but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not accurately measure the Company's exposure to market or credit risks. The maximum terms in years detailed above are not indicative of likely future cash flows as these instruments may be traded in the markets at any time in response to the Company's risk management needs.

12. FINANCIAL INSTRUMENTS (CONTINUED)

Interest Rate Swaps

The Company uses interest rate swaps to manage the fixed and floating interest rate mix of the total debt portfolio. By entering into interest rate swap agreements, the Company agrees to exchange with the Canadian chartered banks the difference between the fixed rate and floating rate interest payments calculated by reference to bankers' acceptances rates and on an agreed notional amount. The notional amount does not represent the amount exchanged by the counterparties, and therefore is not a measure of market or credit exposure. The Company or its subsidiaries have entered into floating to fixed rate swap agreements on $594 million with an average pay rate of 7.1% and an average maturity date of approximately 5 years.

Foreign Currency Contracts

The Company periodically enters into commodity transactions which create Canadian versus United States dollar exposure. To reduce risk and protect margins, the Company enters into forward foreign exchange contracts which establish the foreign exchange rate for the cash flows from these purchase and sale transactions.

In order to fix the costs associated with certain construction and maintenance contracts, the Company entered into forward contracts to purchase Swiss francs and sell United States dollars. At December 31, 2000, Swiss franc contracts with a notional amount of $8 million were outstanding, maturing through to August 15, 2001.

To reduce the impact of changes in the Canadian – United States exchange rate in the translation of certain income denominated in United States dollars arising in 2001, the Company has fixed the translation rate on $US19 million of income at a weighted average rate of 1.5205.

Fair Market Values

The following fair market value (FMV) information is provided solely to comply with financial instrument disclosure requirements. The Company cautions readers in the interpretation of the impact of these estimated fair market values due to the regulated nature of some of the Company's operations. Based on the current regulatory process, any gains or losses arising from the use of financial instruments as approved by respective regulators may be deferred for future disposition by the regulators.

Fair market values have been estimated by reference to quoted market prices for the actual or similar instruments where available. The fair market values of accounts receivable and current liabilities approximate carrying values. The carrying values and approximate fair market values of the Company's financial instruments, excluding energy trading activities which are marked to market, and are therefore recognized in the consolidated financial statements, are:

December 31 ($million)	2000		1999	
	Carrying Value	Approx FMV	Carrying Value	Approx FMV
ASSETS				
Investments	970	967	454	452
Natural gas	—	32	—	—
Foreign currency contracts	—	1	—	3
LIABILITIES				
Long term debt (including current portion)	6,180	6,414	5,872	6,134
Natural gas	—	—	—	6
Interest rate swaps	—	23	—	12

13. INVESTMENTS

December 31 ($million)	2000	1999
Alliance Pipeline, 23.6% interest (Note 8)	408	280
Aux Sable, 23.6% interest (Note 8)	148	68
Vector Pipeline, 30% interest (Note 8)	274	41
Finance contracts (a)	116	42
Other	24	23
	970	454

(a) In 2000, Westcoast Capital Corporation sold certain of its asset-backed finance contracts for proceeds of $19 million, of which $18 million was cash (1999 – $77 million, of which $74 million was cash). The proceeds approximated net book value.

14. FIXED ASSETS

December 31 ($million)	2000	1999
PLANT, PROPERTY AND EQUIPMENT		
Transmission & Field Services		
Natural gas pipeline systems	3,434	3,255
Processing plants	1,306	1,290
Other	200	192
Construction work in progress	28	57
	4,968	4,794
Gas Distribution		
Natural gas pipeline and distribution systems (a)	4,728	4,349
Natural gas storage	636	551
Other	457	393
Construction work in progress	33	38
	5,854	5,331
Power Generation		
Power generation plants	605	292
Other	—	1
Construction work in progress	48	182
	653	475
International		
Power generation plant and other	861	365
Construction work in progress	—	398
	861	763
Services and Other		
Rental assets and other (a) (Note 9)	253	733
	12,589	12,096
ACCUMULATED DEPRECIATION		
Transmission & Field Services	1,690	1,260
Gas Distribution	1,300	1,423
Power Generation	113	111
International	57	29
Services and Other	62	165
	3,222	2,988
	9,367	9,108

(a) Natural gas pipeline and distribution systems includes the depreciated cost of the transmission and distribution plant of the Company's subsidiary, Pacific Northern Gas Ltd. (PNG), of $169 million. Due to the shutdown of a plant by Methanex Corporation, a major customer of PNG, the recovery of the PNG investment in these gas distribution assets is uncertain. Rental assets and other includes the depreciated cost of a customer billing system of $57 million (1999 – $64 million), the recovery of which is uncertain. In accordance with current accounting standards, management uses estimated expected future net cash flows to measure the recoverability of its investment in these assets. The estimation of expected future net cash flows is inherently uncertain and relies to a considerable extent on assumptions regarding current and future economic, market and regulatory conditions. If, in future periods, there are changes in the estimates or assumptions incorporated into the impairment review analysis, the changes could result in an adjustment to the carrying amount of the transmission and distribution plant or the customer billing system.

15. BANK INDEBTEDNESS

The Company, its subsidiaries and joint ventures have operating lines of credit in excess of $1,500 million with Canadian chartered banks that enable the Company, its subsidiaries and joint ventures to borrow directly from the banks, to issue bankers' acceptances, and to support commercial paper programs.

The average year end interest rate applicable to the consolidated bank indebtedness at December 31, 2000 was 6.3% (December 31, 1999 – 5.5%).

16. DEFERRED CHARGES AND OTHER ASSETS

December 31 ($million)	2000	1999
Regulatory	176	168
Development projects (a)(Note 9)	38	51
Debt discount, premium and expense	49	46
Goodwill (Note 8)	32	22
Other	82	65
	377	352

(a) Development projects includes the undepreciated costs associated with the Millennium Pipeline Projects of $17 million. As a result of delays in obtaining regulatory approvals and uncertainty regarding shipper transportation agreements, the recovery of these project costs is uncertain. If, in future years, there are changes in the estimates or assumptions incorporated into the impairment review analysis, including assumptions regarding current and future economic, market and regulatory conditions, the changes could result in an adjustment to the carrying amount of these deferred charges.

17. CUMULATIVE TRANSLATION ADJUSTMENT

The cumulative translation adjustment balance represents the net unrealized foreign currency translation gain on the Company's net investment in self-sustaining foreign businesses.

December 31 ($million)	2000	1999
Beginning of year	(1)	30
Effect of changes in exchange rates during the year on:		
Consolidated operations	17	(30)
Equity accounted investments	1	(1)
End of year	17	(1)

18. CONTINGENCIES

Due to the size, complexity and nature of the Company's operations, various legal matters are pending. In the opinion of management, these matters will not have a material effect on the Company's consolidated financial position or results of operations.

19. RELATED PARTY TRANSACTIONS

The Company's transactions with companies related through joint control are as follows:

For the years ended December 31 ($million)	2000	1999	1998
Engage Energy (to September 30, 2000)			
Natural gas purchases and services	4	8	5
Cantarell Nitrogen Facilities			
Interest income received	—	87	47
Campeche Natural Gas Compression Services Project			
Interest income received	20	10	—
Maritimes & Northeast Pipeline			
Management fee received	9	10	7

These transactions are in the normal course of operations and are recorded at amounts established and agreed between the related parties.

Other accounts receivable in 2000 includes an advance to Compania de Servicios de Compresion de Campeche of $14 million (1999 – $2 million) which bears interest at a fixed rate of 11.78%.

20. INVESTMENTS IN JOINT VENTURES

The following condensed statements of operations, cash flow and balance sheets detail the Company's share of its investments in joint ventures that have been proportionately consolidated:

For the years ended December 31 ($million)	2000	1999	1998
Proportionate Statements of Joint Venture Operations			
Operating revenues	4,504	3,881	4,820
Operating expenses	(4,310)	(3,763)	(4,762)
Other income	9	28	11
Interest on debt	(100)	(62)	(47)
Income taxes	(39)	(4)	(4)
Net income	64	80	18

For the years ended December 31 ($million)	2000	1999	1998
Proportionate Statements of Joint Venture Cash Flow			
Operating activities	156	112	91
Investing activities	(204)	(710)	(363)
Financing activities	96	598	311
Increase in cash and short term investments during the year	48	—	39

December 31 ($million)	2000	1999
Proportionate Joint Venture Balance Sheets		
Current assets	185	610
Investments	1	1
Assets from price risk management activities	—	186
Fixed assets	2,024	1,872
Deferred charges and other assets	99	85
	2,309	2,754
Current liabilities	479	684
Liabilities from price risk management activities	—	154
Long term debt	1,173	1,233
Deferred income taxes	85	43
Westcoast Energy's investment carrying value, including bridge financing	572	640
	2,309	2,754

The Company has a 45% interest in a consortium which has entered into a contract with Pemex Exploración y Producción (PEP) to build, own and operate an offshore gas compression and liquids recovery facility in the Cantarell oil field. The facility will compress natural gas for PEP for processing and ultimate delivery into the Mexican national pipeline system.

The engineering, procurement and construction contractor retained for the project encountered certain construction problems in 2000, resulting in delays to the in-service date beyond the required contract completion date. The financial consequences, if any, of not meeting the required contract completion date are uncertain. The project began commissioning in the first quarter of 2001 and is expected to be in full service early in the second quarter of 2001.

21. SEGMENTED INFORMATION

The operating segments presented are those adopted by senior management based on the Company's internal reporting system.

The operations of the Company have been grouped according to the following business segments:

Transmission & Field Services – natural gas gathering, processing and transmission;
Gas Distribution – natural gas distribution and storage and transmission;
Power Generation – electrical and thermal energy generated from natural gas;
International – international operations;
Services – energy marketing, retail energy services and information technology and financial services;
Other – other activities, including corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

Inter segment revenues are earned in the normal course of operations and are recorded at amounts established and agreed upon between the operating segments.

The Company has international businesses and development projects which are primarily located in the United States, Mexico, Indonesia and China. The percentages of the Company's consolidated operating revenues net of cost of sales, consolidated operating income and consolidated fixed assets and goodwill represented by these businesses and development projects are:

For the years ended December 31	2000	1999	1998
Operating revenues, net of cost of sales	11%	5%	4%
Operating income	13%	13%	2%
Fixed assets and goodwill	15%	14%	

Statements of segmented operations for the years ended December 31 are as follows:

($million, except for share data) 2000	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	825	1,870	128	127	6,613	5	9,568
Inter segment revenues	—	(14)	—	—	(597)	(2)	(613)
Operating revenues	825	1,856	128	127	6,016	3	8,955
Depreciation	(141)	(189)	(17)	(28)	(49)	(2)	(426)
Other operating expenses	(321)	(1,282)	(85)	(46)	(5,933)	(47)	(7,714)
Operating income (loss)	363	385	26	53	34	(46)	815
Interest income	4	—	3	4	2	8	21
Equity earnings	44	—	—	—	—	—	44
Interest expense	(186)	(207)	(6)	(28)	(8)	(81)	(516)
Other items	7	4	2	24	19	36	92
Income (loss) before undernoted items	232	182	25	53	47	(83)	456
Income taxes	(42)	(61)	(9)	(24)	(2)	80	(58)
Non-controlling interest	—	(9)	—	—	—	(1)	(10)
Net income (loss)	190	112	16	29	45	(4)	388
Provision for preferred dividends	(2)	—	—	—	—	(46)	(48)
Net income (loss) applicable to common shares	188	112	16	29	45	(50)	340
Per common share – basic	$1.62	$0.97	$0.13	$0.25	$0.38	$(0.43)	$2.92
Operating cash flow	299	285	32	77	22	(74)	641
Operating cash flow per common share	$2.56	$2.44	$0.28	$0.66	$0.19	$(0.63)	$5.50
Additions to fixed assets and goodwill	192	238	191	92	59	1	773
Total assets	4,761	5,237	628	921	3,253	327	15,127

($million, except for share data) 1999	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	722	1,876	119	68	3,890	2	6,677
Inter segment revenues	(5)	(7)	—	—	(400)	—	(412)
Operating revenues	717	1,869	119	68	3,490	2	6,265
Depreciation	(123)	(183)	(19)	(18)	(56)	(2)	(401)
Other operating expenses	(292)	(1,331)	(91)	(12)	(3,484)	(31)	(5,241)
Operating income (loss)	302	355	9	38	(50)	(31)	623
Interest income	2	1	1	2	3	46	55
Equity earnings	22	—	—	—	—	—	22
Interest expense	(172)	(208)	(6)	(21)	(9)	(83)	(499)
Other items	23	83	7	1	1	7	122
Income (loss) before undernoted items	177	231	11	20	(55)	(61)	323
Income taxes	(22)	(68)	—	(5)	23	26	(46)
Non-controlling interest	—	(9)	—	—	—	(1)	(10)
Net income (loss)	155	154	11	15	(32)	(36)	267
Provision for preferred dividends	(1)	—	—	—	—	(44)	(45)
Net income (loss) applicable to common shares	154	154	11	15	(32)	(80)	222
Per common share – basic	$1.35	$1.35	$0.10	$0.13	$(0.28)	$(0.70)	$1.95
Operating cash flow	238	246	25	38	14	(62)	499
Operating cash flow per common share	$2.09	$2.16	$0.22	$0.33	$0.12	$(0.54)	$4.38
Additions to fixed assets and goodwill	555	292	183	217	105	(35)	1,317
Total assets	4,184	4,608	421	769	1,542	253	11,777

($million, except for share data) 1998	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	680	2,073	95	48	4,711	5	7,612
Inter segment revenues	(8)	(3)	—	—	(225)	—	(236)
Operating revenues	672	2,070	95	48	4,486	5	7,376
Depreciation	(109)	(212)	(15)	(12)	(16)	—	(364)
Other operating expenses	(278)	(1,439)	(62)	(2)	(4,538)	(43)	(6,362)
Operating income (loss)	285	419	18	34	(68)	(38)	650
Interest income	—	4	1	2	5	7	19
Equity earnings	4	—	—	—	—	—	4
Interest expense	(157)	(227)	(7)	(24)	(6)	(67)	(488)
Other items	14	21	—	8	—	24	67
Income (loss) before undernoted items	146	217	12	20	(69)	(74)	252
Income taxes	(16)	(90)	(6)	(4)	23	45	(48)
Non-controlling interest	—	(5)	—	—	—	(1)	(6)
Net income (loss)	130	122	6	16	(46)	(30)	198
Provision for preferred dividends	(2)	—	—	—	—	(35)	(37)
Net income (loss) applicable to common shares	128	122	6	16	(46)	(65)	161
Per common share – basic	$1.22	$1.16	$0.06	$0.15	$(0.44)	$(0.62)	$1.53
Operating cash flow	234	283	25	30	(65)	(59)	448
Operating cash flow per common share	$2.22	$2.68	$0.24	$0.28	$(0.62)	$(0.56)	$4.24
Additions to fixed assets and goodwill	272	339	7	180	105	1	904

22. RECONCILIATION OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company prepares its accounts in accordance with accounting principles generally accepted in Canada (Canadian GAAP) which in the main, parallel accounting principles generally accepted in the United States (US GAAP). The following tables reflect the major differences in accounting principles.

Consolidated net income under US GAAP would be:

For the years ended December 31 ($million, except for share data)	2000	1999	1998
Net income under Canadian GAAP	388	267	198
Adjustments			
Pension and post-retirement benefits other than pensions (a)	2	(7)	(7)
Income taxes (b)	(53)	—	1
Costs of start-up activities (c)	(2)	(45)	—
Initial adoption of mark-to-market accounting (e)	—	(36)	—
Other (d)(f)	1	(2)	—
Net income under US GAAP	336	177	192
Provision for dividends on preferred shares (f)	48	45	37
Net income under US GAAP applicable to common shares	288	132	155
Common shares – weighted average (million)	117	114	105
Earnings per common share under US GAAP – basic	$2.47	$1.16	$1.47
– fully diluted	$2.38		

Consolidated comprehensive income under US GAAP would be:

For the years ended December 31 ($million)	2000	1999	1998
Net income under US GAAP applicable to common shares	288	132	155
Change in the Cumulative Translation Adjustment	14	(31)	9
Comprehensive income under US GAAP	302	101	164

The Consolidated Statements of Comprehensive Income are not required under Canadian GAAP, and the Cumulative Translation Adjustment is recorded as a separate component of Common Shareholders' Equity.

After adjusting for certain differences, selected consolidated balance sheet items under US GAAP would be:

December 31 ($million)	2000	1999
ASSETS		
Current assets (g)	3,563	1,677
Investments (g)	1,023	454
Fixed assets (b)(g)	9,694	9,395
Deferred income taxes (b)	99	113
Deferred charges and other assets (a)(b)(c)(g)	1,614	1,609
LIABILITIES		
Current liabilities (b)(f)(g)	3,829	2,294
Long term debt (f)	5,966	5,545
Long term obligations (a)(g)	412	62
Deferred income taxes (a)(b)	2,051	1,989
Non-controlling interest – preferred shares (f)	135	135
Additional paid in capital (d)	7	4
RETAINED EARNINGS	684	575

Pensions and Post-Retirement Benefits Other than Pensions

(a) Effective January 1, 2000, accounting for pension and post-retirement benefits other than pension under Canadian GAAP has been modified and is similar to the requirements under US GAAP. Pension fund assets are measured at current market values and the accrued pension plan obligations are discounted using current interest rates. Post-retirement benefits other than pension are recorded on an accrual basis.

Previously as permitted by Canadian GAAP, the Company measured the pension fund assets at the average market related values and the accrued pension plan obligations were discounted using management's long term assumptions for interest rates. Post-retirement benefits other than pensions were recorded using the pay-as-you-go method of accounting.

Under US GAAP, the pension fund assets and pension obligations at December 31, 1999 were $537 million and $509 million, respectively.

Income Taxes

(b) Effective January 1, 2000, Canadian GAAP require accounting for income taxes using the liability method of tax allocation, similar to the requirements under US GAAP. However, there remain two significant differences between Canadian and US GAAP:

(i) Canadian GAAP require that deferred income tax balances be adjusted to reflect substantively enacted rates rather than current legislated tax rates under US GAAP.

(ii) Under Canadian GAAP, rate-regulated businesses use the income taxes currently payable method as directed by the regulators. No provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and deferred expenditure items. For these businesses, US GAAP require the recording of deferred income taxes and the corresponding deferred charges which are to be collected from regulated customers in future years.

For business acquisitions under both Canadian and US GAAP, the purchase price allocations reflect the recording of additional deferred income tax liabilities on the excess of the purchase prices over the net book values of assets acquired and liabilities assumed. A corresponding increase to fixed assets is also recorded. As the new recommendations for accounting for income taxes under Canadian GAAP have been applied on a cumulative retroactive basis without restatement of individual prior years, an adjustment under US GAAP is required in years prior to 2000.

Deferred income taxes under US GAAP would be:

December 31 ($million)	**2000**	**1999**
Deferred income taxes under Canadian GAAP	594	333
Difference related to rate change adjustment	53	—
Rate-regulated businesses deferred income taxes	1,338	1,383
Deferred income taxes on excess purchase price amounts	—	289
Other adjustments	(13)	(16)
Deferred income taxes under US GAAP	1,972	1,989

Costs of Start-Up Activities

(c) Effective January 1, 1999, the Statement of Position (SOP) 98-5, Reporting on the Costs of Start-Up Activities, requires that all costs of start-up activities be expensed as incurred rather than deferred and amortized to income over time as permitted under Canadian GAAP. Of the $45 million included in the determination of net income in 1999, $23 million represents the cumulative effect of the accounting change on prior years.

Stock-Based Compensation

(d) Effective January 1, 1996, the Company adopted SFAS 123, Accounting for Stock-Based Compensation, which requires that the fair market value of benefits related to stock-based compensation be charged to income over the applicable vesting period under US GAAP rather than as a capital transaction under Canadian GAAP. The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for stock options granted in 2000, 1999 and 1998, respectively: expected dividend yields of 4.9%, 5.0% and 3.6%, expected volatility of 14.7%, 12.9% and 12.5%, risk free interest rate of 5.3%, 6.0% and 4.8% and expected life of 10 years for all grants.

Energy Marketing Operations

(e) Effective January 1, 1999, the Company adopted mark-to-market accounting for the Company's energy marketing operations. The cumulative effect of a change in accounting principle under US GAAP is included in the determination of 1999 net income. Under Canadian GAAP, the cumulative effect is recorded as a charge to retained earnings.

Debt-Like Preferred Shares

(f) Canadian GAAP require debt-like preferred shares and their dividends to be treated as long term debt and interest expense respectively. Under Securities and Exchange Commission (SEC) rules, these shares are to be recorded as mezzanine debt and the dividend as a charge to retained earnings.

Sale of Finance Contracts and Rental Assets

(g) Under Canadian GAAP, in 2000 the Company sold certain of its asset-backed finance contracts and rental assets to a special purpose entity (SPE), resulting in the removal of the finance contracts, assets and obligation from the consolidated balance sheet. Unlike Canadian GAAP, US GAAP require the SPE to be consolidated in the accounts of the Company because the owner of record of the SPE to which the assets were transferred has not made a substantive residual equity capital investment that is at risk.

Investments in Joint Ventures

(h) Canadian GAAP require the proportionate consolidation of the Company's investments in joint ventures. The SEC regulations permit the filing of financial statements using proportionate consolidation provided that condensed statements of operations, cash flow and balance sheets detailing the Company's share of its investments in joint ventures are provided (Note 20).

Derivative Instruments and Hedging Activities

(i) SFAS 133, Accounting for Certain Derivative Instruments and Hedging Activities, was issued in 1998. This statement, which pursuant to SFAS 137 is effective for the Company January 1, 2001, requires that all derivatives be recorded on the balance sheet at fair value. Derivatives that are not hedges must be adjusted to fair value through income. If the derivative qualifies as a hedge, depending on the nature of the hedge, the effective portion of changes in the fair value of the derivative will either be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of changes in fair value will be immediately recognized in earnings.

Based on the Company's derivative positions at December 31, 2000, the Company will, upon adoption, report an asset from the cumulative net effect of adoption of approximately \$41 million, a deferred regulatory liability of \$45 million, a reduction in assets and liabilities from price risk management activities of \$40 million and a reduction in other comprehensive income of \$4 million.

Transfers and Servicing of Financial Assets and Extinguishments of Liabilities

(j) SFAS 140, Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, was issued in 2000 and replaces SFAS 125. This statement is effective for transfers and servicing of financial assets and extinguishments of liabilities occurring after March 31, 2001. It revises the standards for accounting for securitizations and other transfers of financial assets and collateral and requires certain additional disclosures. The statement clarifies and provides guidance on whether the transferor has relinquished control of the assets transferred. The Company believes that the adoption of SFAS 140 will not have a significant impact on the consolidated financial statements.

23. EMPLOYEE BENEFITS

The Company, its subsidiaries and joint ventures have defined benefit pension plans, defined contribution pension plans and defined benefit plans providing retirement and post-employment health and life insurance benefits for most employees.

Information about the defined benefit plans, in aggregate, is as follows:

For the year ended December 31 ($million)	Pension Benefit Plans 2000	Other Benefit Plans 2000
Accrued benefit obligations		
Balance, beginning of year	518	64
Current service cost	15	2
Interest cost	35	5
Benefits paid	(36)	(2)
Balance, end of year	532	69
Plan assets		
Fair value, beginning of year	493	—
Actual return on plan assets	36	—
Employer contributions	15	—
Employees' contributions	3	—
Benefits paid	(34)	—
Actuarial gains	47	—
Fair value, end of year	560	—
Funded status – plan surplus (deficit)	28	(69)
Unamortized net actuarial gain	(47)	—
Unamortized transitional obligation	32	61
Accrued benefit asset (liability)	13	(8)

The pension fund assets and the projected pension obligations at December 31, 1999 were $537 million and $478 million, respectively.

The non-pension defined benefit plans are unfunded. The accrued benefit obligations and fair value of plan assets of defined benefit pension plans with accrued benefit obligations in excess of plan assets are $141 million and $127 million, respectively.

The following is a summary of the weighted average significant actuarial assumptions used in measuring the Company's accrued benefit obligations:

For the years ended December 31	Pension Benefit Plans 2000	Pension Benefit Plans 1999	Other Benefit Plans 2000
Discount rate	7%	7 – 8%	7%
Expected long-term rate of return on plan assets	7.5%	7 – 8%	—
Rate of compensation increase	3.25%	3.25 – 6%	3.25%

In addition, in determining the expected cost of health care benefit plans, it is assumed that the health care costs will decrease gradually to 5% in 2003 and remain level thereafter.

The Company's net benefit plan expense is as follows:

For the year ended December 31 ($million)	Pension Benefit Plans 2000	Other Benefit Plans 2000
Current service cost	12	2
Interest cost	35	4
Expected return on plan assets	(36)	—
Amortization of transitional obligation	3	4
Net benefit plan expense	14	10

The defined contribution pension expense for the year ended December 31, 2000 was $5 million. The defined contribution and benefit pension expense for the year ended December 31, 1999 and 1998 was $8 million and $15 million, respectively.

24. SUBSEQUENT EVENTS

(a) In November 2000, the Company entered into an agreement to purchase the additional 50% interest in the Empire State Pipeline (Empire), increasing its interest to 100%, for a purchase price of US$75 million. The acquisition is subject to regulatory approval and is expected to be completed in the first quarter of 2001.

(b) In January 2001, the Company sold its remaining 49% interest in NGX Canada Inc. for cash of $10 million, resulting in a pre-tax gain of $7 million.

Consolidated Quarterly Results

Unaudited

($million, except for share data) 2000	For the three months ended Mar-31	Jun-30	Sep-30	Dec-31	Total
Operating revenues	1,754	1,761	2,130	3,310	8,955
Operating expenses	1,477	1,602	2,006	3,055	8,140
Operating income	277	159	124	255	815
Other net expenses	89	86	106	88	369
Income taxes	58	(9)	(18)	27	58
Net income	130	82	36	140	388
Provision for dividends on preferred shares	12	12	12	12	48
Net income applicable to common shares	118	70	24	128	340
Earnings per common share – basic	$1.03	$0.60	$0.20	$1.09	$2.92
Earnings per common share – diluted	$1.01	$0.51	$0.20	$0.98	$2.70

($million, except for share data) 1999	For the three months ended Mar-31	Jun-30	Sep-30	Dec-31	Total
Operating revenues	1,782	1,478	1,330	1,675	6,265
Operating expenses	1,489	1,376	1,264	1,513	5,642
Operating income	293	102	66	162	623
Other net expenses	96	99	19	96	310
Income taxes	64	(14)	(15)	11	46
Net income	133	17	62	55	267
Provision for dividends on preferred shares	10	11	13	11	45
Net income applicable to common shares	123	6	49	44	222
Earnings per common share – basic	$1.08	$0.05	$0.44	$0.38	$1.95
Earnings per common share – diluted	$1.07	$0.05	$0.39	$0.27	$1.78

The Company's natural gas distribution businesses are highly seasonal, with the majority of gas deliveries occurring during the winter heating season from mid-October to mid-April. Gas sales during this period typically account for approximately two-thirds of annual gas distribution revenues, resulting in strong first quarter results, second and third quarters that show either small profits or losses, and strong fourth quarter results.

The earnings contribution of the Company's natural gas distribution businesses are also subject to weather variances. Excluding the positive and negative impact of weather, earnings per common share for the Company were $2.96 in 2000 compared with $2.10 in 1999.

For the three months ended (dollar / share) 2000	Mar-31	Jun-30	Sep-30	Dec-31	Total
Net income per common share	$1.03	$0.60	$0.20	$1.09	$2.92
Weather impact – gas distribution	$0.09	$0.01	$(0.01)	$(0.05)	$0.04
Weather normalized net income per common share	$1.12	$0.61	$0.19	$1.04	$2.96

For the three months ended (dollar / share) 1999	Mar-31	Jun-30	Sep-30	Dec-31	Total
Net income per common share	$1.08	$0.05	$0.44	$0.38	$1.95
Weather impact – gas distribution	$0.05	$0.05	—	$0.05	$0.15
Weather normalized net income per common share	$1.13	$0.10	$0.44	$0.43	$2.10

Ten-Year Review

Unaudited

	2000	1999	1998
FINANCIAL			
OPERATIONS ($million)			
Operating revenues	8,955	6,265	7,376
Operating expenses	8,140	5,642	6,726
Operating income	815	623	650
Other net expenses	369	310	404
Income taxes	58	46	48
Net income from continuing operations	388	267	198
Discontinued operations	—	—	—
Net income (loss)	388	267	198
Provision for dividends on preferred shares	48	45	37
Net income (loss) applicable to common shares	340	222	161
Dividends on common shares	150	146	133
Operating cash flow			
– From continuing operations	641	499	448
– After discontinued operations	641	499	448
PER COMMON SHARE (dollars)			
Net income (loss) – basic			
– From continuing operations	$2.92	$1.95	$1.53
– After discontinued operations	$2.92	$1.95	$1.53
Operating cash flow			
– From continuing operations	$5.50	$4.38	$4.24
– After discontinued operations	$5.50	$4.38	$4.24
Dividends	$1.28	$1.28	$1.26
ASSETS ($million)			
Fixed assets	9,367	9,108	8,569
Investments	970	454	374
Assets from price risk management activities	561	186	—
Current assets	3,546	1,677	1,596
Deferred income taxes	306	—	—
Deferred charges and other assets	377	352	281
Total assets	15,127	11,777	10,820
CAPITALIZATION ($million)			
Long term debt	5,971	5,550	5,297
Liabilities from price risk management activities	612	175	—
Preferred shareholders' equity	865	865	716
Common shareholders' equity	2,764	2,395	2,368
Deferred income taxes	880	333	340
Current liabilities	3,869	2,293	1,935
Non-controlling interest in subsidiary companies	166	166	164
Total equity and liabilities	15,127	11,777	10,820

1997	1996	1995	1994	1993	1992	1991
7,312	4,875	4,184	3,827	3,674	1,818	1,501
6,519	4,088	3,445	3,208	3,107	1,473	1,236
793	787	739	619	567	345	265
432	460	436	360	353	224	177
123	115	109	95	68	36	15
238	212	194	164	146	85	73
—	—	—	—	—	(161)	10
238	212	194	164	146	(76)	83
28	19	18	13	13	11	6
210	193	176	151	133	(87)	77
122	105	81	76	65	49	45
522	543	384	342	363	233	189
522	543	384	342	385	292	249
$2.06	$1.96	$2.01	$1.76	$1.70	$1.23	$1.18
$2.06	$1.96	$2.01	$1.76	$1.70	$(1.45)	$1.36
$5.10	$5.50	$4.41	$3.98	$4.64	$3.88	$3.33
$5.10	$5.50	$4.41	$3.98	$4.91	$4.87	$4.39
$1.20	$1.05	$0.93	$0.89	$0.82	$0.80	$0.80
8,025	7,304	7,056	6,390	5,674	5,678	3,535
195	184	162	100	32	87	23
—	—	—	—	—	—	—
1,574	1,328	994	974	939	844	364
—	—	—	—	—	—	—
281	250	239	182	145	118	102
10,075	9,066	8,451	7,646	6,790	6,727	4,024
4,941	4,743	4,715	3,647	3,383	3,396	1,780
—	—	—	—	—	—	—
570	445	245	245	120	195	75
2,056	1,890	1,542	1,417	1,320	1,005	896
400	366	396	399	391	593	368
2,045	1,517	1,441	1,828	1,465	1,400	827
63	105	112	110	111	138	78
10,075	9,066	8,451	7,646	6,790	6,727	4,024

Ten-Year Review

Unaudited

	2000	1999	1998
STATISTICAL			
VOLUMES (Bcf)			
British Columbia Pipeline Division	682	670	688
Foothills Pipe Lines	1,155	1,131	940
Empire State Pipeline	117	105	93
Maritimes & Northeast Pipeline	290	—	—
Union Gas*	1,263	1,222	1,127
Other Gas Distribution#	72	122	139
	3,579	3,250	2,987
RATE BASE ($million)			
British Columbia Pipeline and Field Services Divisions	2,285	2,294	2,287
Foothills Pipe Lines (proportionate share – Phase I – 27%)	225	224	185
Empire State Pipeline (proportionate share – 50%)	114	120	131
Union Gas* ^	2,867	2,733	3,206
Other Gas Distribution#	625	591	851
	6,116	5,962	6,660
NUMBER OF CUSTOMERS (thousand)			
Union Gas*	1,123	1,099	1,075
Other Gas Distribution#	111	107	344
	1,234	1,206	1,419
COMMON SHARES			
Shares outstanding at year-end	121,443,366	114,847,515	112,670,767
Toronto Stock Exchange price ranges			
– high	$36.60	$31.60	$36.35
– low	$20.10	$22.40	$27.25
Number of common shareholders at year-end	8,047	8,556	8,645
Employees at year-end (consolidated – excluding joint ventures)	5,455	5,648	6,300

* amalgamated with Centra Gas Ontario Inc. on January 1, 1998.

^ transferred approximately $500 million of net assets to Union Energy on January 1, 1999.

\# includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively.

1997	1996	1995	1994	1993	1992	1991
688	667	647	605	579	512	465
935	927	920	852	615	534	457
98	101	114	43	6	—	—
—	—	—	—	—	—	—
1,193	1,137	1,166	1,034	991	317	127
163	169	165	160	156	147	139
3,077	3,001	3,012	2,694	2,347	1,510	1,188
2,273	2,114	1,807	1,353	1,236	1,142	914
189	193	193	192	169	157	156
129	130	89	92	88	—	—
3,043	2,830	2,718	2,496	2,304	2,115	489
937	888	989	937	899	837	763
6,571	6,155	5,796	5,070	4,696	4,251	2,322
1,041	1,002	965	932	892	852	190
387	372	358	347	332	318	307
1,428	1,374	1,323	1,279	1,224	1,170	497
103,245,876	100,747,253	87,972,872	86,444,582	85,318,602	72,678,965	57,255,169
$33.50	$24.40	$22.75	$24.63	$22.63	$21.13	$21.50
$22.65	$20.00	$19.25	$19.63	$16.25	$15.00	$19.00
8,753	8,499	8,447	8,782	8,602	7,828	6,043
5,932	5,991	6,380	6,258	6,043	6,257	3,351

Directors

William C. Brown was formerly President and CEO of BC Sugar Refinery, Limited, and is a Director of Duke Seabridge Limited and TimberWest Forest Corp. Mr. Brown was first elected to the Board in 1995 and is a member of the Audit and the Human Resources and Compensation Committees.

R. Donald Fullerton is a Director of the Canadian Imperial Bank of Commerce, George Weston Limited, Hollinger Inc., Asia Satellite Telecommunications Company Limited, and is an Advisory Board Member of IBM Canada Limited. Mr. Fullerton was first elected to the Board in 1993 and is a member of the Audit and the Human Resources and Compensation Committees.

Wilbert H. Hopper was formerly Chairman and CEO of Petro-Canada, and served as Chairman of the Board of Westcoast Energy from 1983 to 1992. Mr. Hopper was first elected to the Board in 1979. He is Chair of the Audit Committee and is a member of the Executive Committee.

Lorna R. Marsden is President and Vice-Chancellor of York University, and is a Director of Manulife Financial and Gore Mutual Insurance Co. Dr. Marsden was first elected to the Board in 1995 and is a member of the Audit and the Human Resources and Compensation Committees.

George L. Mazanec was formerly Vice Chairman of PanEnergy Corp. (now part of Duke Energy Corporation), and is a Director of National Fuel Gas Company, Aegis Insurance Services, Inc. and Northern Trust Bank of Texas. Mr. Mazanec was first elected to the Board in 1998 and is a member of the Audit and the Environment, Health and Safety Committees.

William H. Neville is Chairman of The Strategies Group, consultants in business, government relations, strategic planning and public policy. Mr. Neville was first elected to the Board in 1988. He is Chair of the Corporate Governance Committee and is a member of the Environment, Health and Safety Committee.

Marnie Paikin is a Director of Atomic Energy of Canada Limited and Union Gas Limited, and is a Commissioner of the Ontario Human Rights Commission. Ms. Paikin was first elected to the Board in 1993. She is Chair of the Environment, Health and Safety Committee and is a member of the Corporate Governance Committee.

Daniel U. Pekarsky is President of The Corporate Advisory Group Inc., consultants in financial and strategic planning, and is a Director of Search Energy Corp. Mr. Pekarsky was first elected to the Board in 1993. He is Chair of the Executive Committee and is a member of the Corporate Governance Committee.

Michael E.J. Phelps is Chairman and CEO of Westcoast Energy. Mr. Phelps is a Director of Canfor Corporation, the Canadian Imperial Bank of Commerce, Canadian Pacific Limited and Foothills Pipe Lines Ltd. He was appointed President and CEO in 1988, and became Chairman in 1992. Mr. Phelps was first elected to the Board in 1987 and is a member of the Executive Committee.

William G. Saywell is Vice Chairman of Intercedent Ltd., a business development and management consulting firm, and is a Director of the Bank of Tokyo-Mitsubishi (Canada) and Western Garnet International Ltd. Dr. Saywell was first elected to the Board in 1992 and is a member of the Corporate Governance and the Environment, Health and Safety Committees.

Arthur H. Willms was formerly President and COO of Westcoast Energy, and is Chairman and a Director of Union Gas Limited, Pacific Northern Gas Ltd., and Centra Gas British Columbia Inc., and is a Director of Gulf Canada Resources Limited and Foothills Pipe Lines Ltd. Mr. Willms was first elected to the Board in 1983 and is a member of the Environment, Health and Safety and the Executive Committees.

W. Robert Wyman was formerly Chairman of BC Hydro and a Vice-Chairman of RBC Dominion Securities Inc., and is Chairman and a Director of Suncor Energy Inc. Mr. Wyman was first elected to the Board in 1993. He is Chair of the Human Resources and Compensation Committee and is a member of the Executive Committee.

Edwin C. Phillips is Director Emeritus of Westcoast Energy. Mr. Phillips, who was CEO of Westcoast Energy from 1975 to 1983, served as a Company Director from 1969 to 1989.

Senior Officer and Management Group

CORPORATE

Michael E.J. Phelps
Chairman and Chief Executive Officer

Graham M. Wilson
Executive Vice President and Chief Financial Officer

Kenneth E. Rekrutiak
Senior Vice President and Chief Information Officer

David G. Unruh
Senior Vice President, Law and Corporate Secretary

Eric L. Schwitzer
Senior Vice President, Strategic Development

P. Wayne Soper
Senior Vice President, External Relations

Bohdan I. Bodnar
Vice President, Human Resources and Administration

Robert R. Foulkes
Vice President, Corporate Communications

TRANSMISSION & FIELD SERVICES

Irvine J. Koop
Executive Vice President
President and Chief Executive Officer, Pipelines and Midstream

Douglas J. Haughey
President, Westcoast Energy Pipeline and Field Services Divisions

GAS DISTRIBUTION

Robert T. Reid
Executive Vice President
President and Chief Executive Officer, Union Gas Limited

Jac W. Kreut
President, Centra Gas British Columbia Inc.

POWER GENERATION AND INTERNATIONAL

D. Michael G. Stewart
Executive Vice President, Business Development

Jeffry M. Myers
President, Westcoast Power Inc.

SERVICES

Michael G. Broadfoot
President and Chief Executive Officer, Engage Energy Canada, Inc.

Vaughn C. Goettler
President and Chief Executive Officer, Union Energy Inc.

Murray P. Birch
Vice President
President, Westcoast Capital Corporation

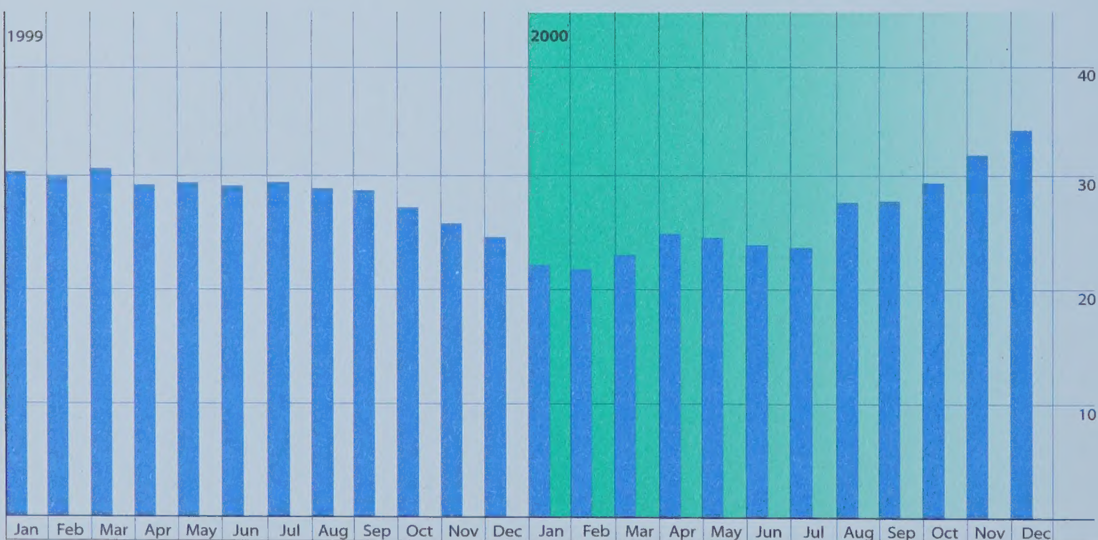
Anthony M. Haines
President, Enlogix Inc.

Investor Information

STOCK MARKET PRICE RANGES, EARNINGS, AND DIVIDENDS PER COMMON SHARE

	Toronto ($Cdn)		New York ($US)		Earnings ($Cdn)	Dividends ($Cdn)
	Low	High	Low	High		
2000						
January – March	20.10	25.25	13.50	17.38	1.03	0.32
April – June	22.80	25.75	15.50	17.69	0.60	0.32
July – September	23.50	28.95	15.88	19.56	0.20	0.32
October – December	28.25	36.60	18.56	24.44	1.09	0.32
					2.92	1.28

	Toronto ($Cdn)		New York ($US)		Earnings ($Cdn)	Dividends ($Cdn)
	Low	High	Low	High		
1999						
January – March	28.90	31.60	19.00	20.81	1.08	0.32
April – June	27.75	30.05	19.00	20.63	0.05	0.32
July – September	26.75	29.85	18.13	20.06	0.44	0.32
October – December	22.40	28.00	15.19	18.88	0.38	0.32
					1.95	1.28



Monthly Average Share Price

Toronto Stock Exchange (TSE)
($Cdn)

Investor Information

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Westcoast Energy's Dividend Reinvestment and Share Purchase Plan provides registered holders of Westcoast Energy common shares and convertible preferred shares with two convenient and economic ways to increase their holdings in the Company.

Registered shareholders may elect to reinvest the cash dividends paid on all or some of their common and convertible preferred shares in additional common shares of the Company, and are also entitled to make optional cash purchases of common shares through the Plan in amounts from $50 to $5,000 per calendar quarter.

The Plan allows participants to acquire new common shares through the reinvestment of dividends at 95% of the average market price as defined in the Plan. Optional cash purchases are made at the average market price. Participants do not pay any brokerage commissions or other fees on the reinvestment of dividends or the optional cash purchase of new shares through the Plan.

All notices and enquiries relating to the Plan should be addressed to the Computershare Trust Company at:

Computershare Trust Company of Canada
510 Burrard Street
Vancouver, British Columbia
Canada V6C 3B9

Telephone:	(604) 661-0222
Facsimile:	(604) 683-3694
Toll Free:	(888) 661-5566
Internet:	www.computershare.com
Email:	caregistryinfo@computershare.com

SHAREHOLDER AND CORPORATE RELATIONS

Shareholders or others wishing to obtain copies of this Annual Report, quarterly reports, the 2001 Annual Information Form, and other corporate documents should contact the Company either by letter, addressed to the attention of the Corporate Secretary, or by telephone at (604) 488-8000.

Portfolio managers, investment analysts, and other investors requesting financial information respecting the Company should contact:

Thomas M. Merinsky
Manager, Investor Relations

Telephone:	(604) 488-8021
Facsimile:	(604) 488-8192

All other enquiries by media, the general public, and others respecting the Company should be directed to:

Robert R. Foulkes
Vice President, Corporate Communications

Telephone:	(604) 488-8093
Facsimile:	(604) 488-8068

STOCK EXCHANGES AND SYMBOLS

Westcoast Energy common shares are listed on the Toronto and New York stock exchanges.
In Canada – W
In the United States – WE

Westcoast Energy preferred shares are listed on The Toronto Stock Exchange.

8.08% First Preferred, Series 2 – W.PR.D
4.90% First Preferred, Series 5 – W.PR.F
4.72% First Preferred, Series 6 – W.PR.G
5.50% First Preferred, Series 7 – W.PR.H
5.60% First Preferred, Series 8 – W.PR.J
5.00% First Preferred, Series 9 – W.PR.K

AUDITORS

Ernst & Young LLP
P.O. Box 10101, Pacific Centre
700 West Georgia Street
Vancouver, British Columbia
Canada V7Y 1C7

REGISTRARS AND TRANSFER AGENTS

Common Shares
Computershare Trust Company of Canada
Vancouver, Calgary, Toronto, Montreal

Registrar and Transfer Company
Cranford, New Jersey

Preferred Shares
Computershare Trust Company of Canada
Vancouver, Calgary, Winnipeg, Toronto, Montreal

REGISTRAR AND TRUSTEE

Debentures
Computershare Trust Company of Canada
Vancouver, Calgary, Regina, Toronto, Montreal

TAXATION

A resident of the United States receiving investment income generated in Canada is subject to withholding tax under the Income Tax Act of Canada and the Canada-United States Income Tax Convention. With certain exceptions, dividends paid by the Company are subject to withholding tax at a rate of 15%.

WESTCOAST ENERGY INC.
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Canada V6E 3K9

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Email:	contactus@westcoastenergy.com

VICE PRESIDENT, CORPORATE COMMUNICATIONS
Robert R. Foulkes (604) 488-8093

MANAGER, INVESTOR RELATIONS
Thomas M. Merinsky (604) 488-8021

DUPLICATE PUBLICATIONS

Registered holders of the Company's shares may receive more than one copy of Company publications. Shareholders can assist the Company in eliminating such duplication by contacting the Computershare Trust Company of Canada in Vancouver at (888) 661-5566 (Toll free).

Cover and Coated Stock:
Centura Gloss
10% total recovered fiber,
all post-consumer fiber

Uncoated Stock:
New Life Opaque
Over 50% recycled paper including
30% post-consumer fiber, 70% ECF virgin fiber

Printed in Canada